BEFORE THE BOARD OF OIL, GAS AND MINING

DEPARTMENT OF NATURAL RESOURCES

IN AND FOR THE STATE OF UTAH

IN THE MATTER OF THE REQUEST FOR AGENCY ACTION OF WOLVERINE GAS AND OIL COMPANY OF UTAH, LLC, FOR AN ORDER AUTHORIZING THE FLARING AND VENTING OF GAS IN EXCESS OF THE AMOUNTS ALLOWED UNDER UTAH ADMIN. CODE RULE R649-3-20(1.1) FROM THE WOLVERINE FEDERAL ARAPIEN VALLEY 24-1 AND PROVIDENCE FEDERAL 24-4 WELLS LOCATED IN THE W1/2 OF SECTION 24, TOWNSHIP 20 SOUTH, RANGE 1 EAST, SLM, SANPETE COUNTY, UTAH.

DOCKET NO. 2010-010 CAUSE NO. 269-01

TAKEN AT: Department of Natural Resources
1594 West North Temple, Room 1040
Salt Lake City, Utah

DATE: Wednesday, February 24, 2010

TIME: 11:24 A.M.

REPORTED BY: Michelle Mallonee, RPR

APPEARANCES

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INDEX

Docket No. 2010-010 Cause No. 269-01

Wednesday, February 24, 2010

(The proceedings began at 11:24 a.m.)

CHAIRMAN JOHNSON: The second matter this morning is Docket No. 2010-010 Cause No. 269-01 - In the Matter of the Request for Agency Action of Wolverine Gas and Oil Company of Utah, LLC, for an Order Authorizing the Flaring and Venting of Gas in Excess of the Amounts Allowed under Utah Admin. Code Rule R649-3-20(1.1) from the Wolverine Federal Arapien Valley 24-1 and Providence Federal 24-4 Wells Located in the W1/2 of Section 24, Township 20 South, Range 1 East, SLM, Sanpete County, Utah.

Mr. MacDonald, you are representing the petitioner?

MR. MACDONALD: Yes, I am, Mr. Chairman.

MR. ALDER: Steve Alder representing the Division.

CHAIRMAN JOHNSON: Mr. MacDonald, why don't we get started and see if we can get through your first witness, maybe before we take a break for lunch.

MR. MACDONALD: That's fine, Mr. Chairman.

CHAIRMAN JOHNSON: Let's give Mr. Gill one more minute to get back. I think he's talking to someone from the previous matter. Then we'll get going.

MR. MACDONALD: If you'd like, Mr. Chairman, we can get the witnesses at least sworn in.

CHAIRMAN JOHNSON: That would be a good idea. Let's do that.

MR. MACDONALD: Mr. Chairman, Fred MacDonald of Beatty & Wozniak on behalf of the petitioner, Wolverine Gas and Oil Company of Utah, LLC.

With me today, and will be testifying, are Mr. Richard Moritz, Ms. Emily Hartwick, Mr. Thomas Zadick, and Mr. Edward Higuera. And I ask that they be sworn in at this time.

CHAIRMAN JOHNSON: Let's do that, please.

THE REPORTER: You and each of you do solemnly swear the testimony you are about to give will be the truth, the whole truth, and nothing but the truth so help you God?

(The witnesses answered in the affirmative.)

MR. MACDONALD: Richard Moritz is the vice president and landman to the Wolverine Gas and Oil Corporation, which is the parent company of the petitioner, and also a member of the petitioner itself.

Ms. Hartwick is the geologist of Wolverine Gas and Oil Corporation.

Mr. Zadick is the contract reservoir engineer for Wolverine -- the petitioner, and also for the parent.

And Mr. Higuera is the manager in development of Wolverine Gas and Oil Corporation, and a petroleum engineer by trade.

The resumes of all four witnesses were submitted collectively as Exhibit A in this cause. Based on that exhibit, with the stipulation of the Division and in accordance with the previous practice of the Board, I request that the parties be recognized as experts in the fields of petroleum land management, geology, reservoir engineering, petroleum engineering, respectively, for purposes of this cause.

CHAIRMAN JOHNSON: Mr. Alder?

MR. ALDER: Have the witnesses testified previously as exhibits (sic), either here or in other jurisdictions?

MR. MACDONALD: I believe the resumes indicate. I know Moritz has previously been recognized as an expert in -- before the Michigan Oil and Gas Conservation Commission. Mr. Zadick has been recognized in several different commissions, I'm sure.

Neither Mr. Higuera nor Ms. Hartwick have previously been recognized in court.

MR. ALDER: And I apologize. But I did not have time to review those resumes. If you could just put a little bit of their background on the record, I'd appreciate it.

MR. MACDONALD: Would it be okay with the Board and the Division to just proffer that?

MR. ALDER: Yes, that would be fine.

MR. MACDONALD: Mr. Moritz is a lawyer who has been in the practice -- he's a lawyer, went to law school -- Thomas Cooley Law School in Michigan. He's been a landman for over 30 years. He's the vice president of land for Wolverine Gas, Incorporation; has had numerous experience with land contracts; and is also in charge of the land department in supervising the development of the Wolverine unit, which is at issue today.

MR. ALDER: Are you asking that he be recognized as an expert?

MR. MACDONALD: Yes, an expert in petroleum land management.

Ms. Hartwick is a geologist graduate, just had her thesis defended for her master's -- her Ph.D., excuse me -- master's. She's been a geologist with Wolverine since 2006. Resume outlines her other credentials and courses that she's taken. I ask that she be recognized as expert in geology.

Mr. Zadick has a long and distinguished resume for his efforts. He has for worked for Shell for many years; has been a consulting reservoir engineer. And again, he's been previously recognized by numerous commissions as an expert in reservoir engineering.

Mr. Higuera is a petroleum engineer, has a degree from Texas A&M. He's worked for various companies, and has worked for Wolverine for what -- six years now?

MR. HIGUERA: Since 2004.

MR. MACDONALD: Yeah, six years. And again, I think his credentials, and his outline in the resume, and his courses that he's taken also qualify him as an expert in petroleum engineering.

MR. ALDER: Mr. Chairman, if I might just ask a question of Ms. Hartwick, or ask that there be proffered some information about her employment in Utah as a geologist?

MR. MACDONALD: Ms. Hartwick has been employed with Wolverine, and her primary responsibility in this area in the Wolverine unit has been her experience with the geology. Her thesis, actually, was based on some of the information developed from Wolverine's unit; and that is her experience with Utah, as well.

MR. ALDER: Thank you, Mr. Chairman, for that indulgence. We prefer to have stipulated beforehand. But I think the Division has no objection to their being recognized as experts in those areas.

CHAIRMAN JOHNSON: Does the Board have any questions on their qualifications? Any concerns? Then we'll recognize your witnesses as experts, as you requested.

MR. MACDONALD: Thank you, Mr. Chairman.

I also want to confirm that the Board has received the supplement to Exhibit E, that was filed last week. Again, that is just the additional certifications, the receipts from the mailing. And also, the substitute Exhibit P which was filed, and that the Board allowed me to file by Order last week. There was some mislabeling of coloring related to the graphs on that, but there was no substantive changes to the graphs that were depicted on Exhibit P.

CHAIRMAN JOHNSON: Let me make sure. Which exhibit did you say that it was?

MR. MACDONALD: It's substitute Exhibit P.

CHAIRMAN JOHNSON: Okay. So that's this one?

MR. MACDONALD: Yes, correct.

CHAIRMAN JOHNSON: Okay. All right. Thank you.

MR. MACDONALD: Thank you. Finally, Mr. Chairman, I'd like to confirm again that it's acceptable for me to move for admission of the exhibits at the end of my presentation-in-chief.

CHAIRMAN JOHNSON: That would be fine.

MR. MACDONALD: Thank you. Members of the Board, Wolverine is the operator of the Wolverine Federal Exploratory Unit located in Sanpete and Sevier Counties. The Board is undoubtedly aware of the significant hinge line oil discovery made by Wolverine in 2004, in the area of the unit known as the Covenant field, which is located in Sevier County.

In 2008 and 2009, Wolverine drilled the two wells at issue today, which are approximately 22 miles to the northeast of the Covenant field, in an area of the unit known as the Providence field, which is located in Sanpete County. Preliminary testing suggests that the Providence field might constitute another economic hinge line oil discovery consisting of two separate productive intervals, the Navajo 1 and the Navajo 2, which you will hear about through the testimony.

But the Providence field is not nearly as prolific as the Covenant discovery. In addition, unlike the Covenant field, the two Providence wells have associated carbon dioxide and other inert gases, as well as some hydrogen sulfide. It is the presence of these associated gases that lead to Wolverine's request before you today.

Specifically, in order to test and further produce the wells, Wolverine needs to flare and vent the gas. Utah Administrative Code Rule R649-3-20(1.1) sets limitations on how much gas can be flared and vented without Board approval. Through its initial testing, Wolverine has now reached those administrative limitations and has shut-in the wells pending Board approval of additional flaring and venting.

Utah Administrative Code Rule R649-3-20(5) sets forth the information a petitioner must supply for the Board's consideration of additional flaring and venting authorization. Bottom line is, the Board must conclude that the gas cannot be put to a beneficial use, and that the marketing or conservation of the gas is not economically viable considering the total well production, meaning both oil and gas revenue streams.

Wolverine believes that the testimony and exhibits to be submitted into evidence today will establish just that, with respect to these two wells. However, it is important to initially point out -- and for the Board members to keep in mind throughout this presentation -- that the wells have had very limited testing -- limited testing and production to date, and reflect a very complex fluid system. In short, flaring and venting authorization is required to allow additional production and testing to determine, first and foremost, if the Providence field can be produced economically and on a long-term basis.

You will note that Wolverine has asked for indefinite flaring and venting at unrestricted rates. This is because, as you will learn shortly, the data presented is based on a model that, while currently representing Wolverine's best approximation of reservoir characteristics, might significantly change as the additional testing and production is achieved, including, most significantly, the amount of gas that potentially would need to be flared and vented.

However, being cognizant of the Board's statutory duties, Wolverine has agreed to submit written annual reports to the Division to allow the Agency to determine if any significant changes have occurred, such that the flaring and venting authorization should be revisited by the Board through submission of additional testimony in exhibits at hearing.

Wolverine also will take all steps required under applicable State and Federal regulations to ensure the protection of the health, safety, and welfare of the general public, including, but not limited to, continued compliance with Federal Onshore Order No. 6 and Utah Administrative Code Rule R649-3-12, which address hydrogen sulfide safety measures. Wolverine will also, presuming the request is granted, file a conforming NTL-4A application with the Bureau of Land Management, as is required under federal regulation. The BLM is involved because the lease at issue and the unit involved are all federal.

The Board has jurisdiction over this matter pursuant to Utah Code Annotated Section 40-6-5(3)(f) and Utah Administrative Code Rule R649-3-20(5).

Notice was sent via certificate mail, return receipt requested, to all production interest owners in the federal lease upon which the two wells are located, and to both the state and local field, which is the Richfield office of the Bureau of Land Management, which as I mentioned, is the surface owner, the lessor under the lease, and the administrator of the unit. The mailings were sent to these parties at their last address as disclosed by the relevant Bureau of Land Management and Sanpete County realty records. And the record will reflect that all the mailings were received by the parties.

The record will also reflect that notice was duly published February 3, 2010, in the Sanpete Messenger; on February 4, 2010, in the Gunnison Valley Gazette; and on February 7, 2010, in the Salt Lake Tribune and Deseret Morning News.

A telephonic conference between Wolverine, the Division, and the State and Richfield BLM offices was held on February 4, 2010, to discuss the request. Additional production forecasts and economics clarifying and supplementing exhibits previously submitted by Wolverine on January 25, were requested by the Bureau of Land Management, which Wolverine supplied to all of the agencies by email on February 10.

The Division submitted a staff memorandum on Wolverine's request on February 18, 2010. In it, the Division stated that it anticipated supporting further flaring and venting for the wells, but how much and for how long remained to be determined, based on Wolverine's presentation as to reservoir type, reserves, and production options. Wolverine believes it will adequately address those issues today.

The Richfield BLM office had initially filed a Motion for Continuance, but it was withdrawn on February 18, 2010. No other formal written response to the request by either of the BLM offices has been filed with the Board. Finally, no other objections or responses were received.

At this time I'd like to begin my examination of Mr. Moritz.

RICHARD D. MORITZ,

having been first duly sworn,

was examined and testified as follows:

DIRECT EXAMINATION

BY MR. MACDONALD:

MR. MACDONALD: Mr. Moritz, would you please state your name and address for the record.

MR. MORITZ: Yes. Richard Moritz, One Riverfront Plaza, 55 Campau Northwest, Grand Rapids Michigan, 49503.

MR. MACDONALD: Mr. Moritz, what is your relationship to the petitioner?

MR. MORITZ: Vice president of land.

MR. MACDONALD: And that's of the parent corporation of the petitioner. Is that correct?

MR. MORITZ: Correct.

MR. MACDONALD: And you are also a member of the petitioner. Is that correct?

MR. MORITZ: Correct.

MR. MACDONALD: All right. Would you please outline for the Board what is the petitioner's corporate and bonding status?

MR. MORITZ: Yes. Wolverine is a Michigan limited liability company with its principal place of business in Grand Rapids, Michigan. It is duly authorized to conduct business in Utah. It's fully bonded with all appropriate federal and state agencies.

MR. MACDONALD: Since this is Wolverine's first opportunity to appear before the Board, would you give it a little bit of background about the company and its parent?

MR. MORITZ: Yes. Wolverine is the operating subsidiary of its parent, Wolverine Gas and Oil Corporation, for purposes of the Wolverine unit. The parent is a privately owned Michigan corporation with over 40 employees. Its principals have been in the oil and gas business for over 40 years and have numerous holdings throughout the Midwest and Rockies. It is one of the largest oil producers in the state of Utah, with over 8000 barrels a day. The Wolverine unit was formed by Wolverine in the summer of 2003.

MR. MACDONALD: Mr. Moritz, I'm now going to show you what have been marked as Exhibits B, C, and D for purposes of this cause. Do you recognize those exhibits?

MR. MORITZ: Yes.

MR. MACDONALD: Were they prepared by Wolverine personnel at your request and with your input and review?

MR. MORITZ: Yes.

MR. MACDONALD: All right. Directing your attention now to Exhibit B, which again is replicated on the PowerPoint presentation behind the Board, would you please explain to the Board what this exhibit represents?

MR. MORITZ: Yes. It's a regional location map, showing in the blue the outline of the Wolverine federal unit; and in red, the Covenant field; and then to the northeast, the Providence field. And then in the inset box, it shows the two wells we're discussing today, the Arapien Valley 24-1, and the Providence Federal 24-4.

MR. MACDONALD: And again, the Covenant field was discovered in 2004. Is that correct?

MR. MORITZ: Correct.

MR. MACDONALD: And the Providence field was discovered in 2008-2009. Is that correct?

MR. MORITZ: That is correct.

MR. MACDONALD: Directing your attention now to Exhibit C, which again is replicated behind the Board on the screen through the PowerPoint presentation. Would you please advise the Board of its significance?

MR. MORITZ: Yes. It reflects the well locations upon federal lease 80907, which is fully committed to the Wolverine unit. The green represents the entire lease.

MR. MACDONALD: All right. It's important to recognize, again, that the wells are both located on that leasehold. Is that correct.

MR. MORITZ: That's correct.

MR. MACDONALD: All right. Now moving your direction to Exhibit D. Would you please explain to the Board its significance?

MR. MORITZ: Yes. It's a picture of the well locations, and illustrating the remote federal land. The 24-1 well is at least two miles away, and the 24-4 well is at least one mile away from any permanent residence.

It is also intended to show the minimal effect of any venting or flaring on visual and health and safety impacts.

MR. MACDONALD: Mr. Moritz, now I'm going to direct your attention to a pleading that's on file in this matter, that I've prepared. This is the Certificate of Service of the mailing of the Request for Agency Action. I would like you to review the names and addresses shown on that exhibit. Do you recognize those parties?

MR. MORITZ: Yes, I do.

MR. MACDONALD: Okay. And who are those parties?

MR. MORITZ: The names -- I recognize the names as the -- all the production interest owners in the federal lease 80907, and both the state and Richfield field offices of the BLM as the surface owner, lessor under the lease, and the administrator of the unit.

MR. MACDONALD: And how were these names and addresses compiled?

MR. MORITZ: The information was compiled from Wolverine's internal land records and a search by GeoScout to relevant BLM and Sanpete County records, prior to filing the Request.

MR. MACDONALD: All right. I'd like to direct the Board now to what has been marked as Exhibit E. This is true and correct copies of return receipts received by my office of the mailing of the request. Again, it was supplemented last week to reflect return receipts received after January 25, which was the exhibit filing deadline. This will be proffered into evidence at the end of the presentation-in-chief. And it should be noted that all of the parties to whom the Request was mailed to did receive that copy.

Mr. Chairman, that concludes my examination of Mr. Moritz.

CHAIRMAN JOHNSON: Mr. Alder?

MR. ALDER: Division has no questions.

CHAIRMAN JOHNSON: Does the Board have any questions for Mr. Moritz?

Thank you, Mr. Moritz.

MR. MORITZ: Thank you.

EMILY E. HARTWICK,
having been first duly sworn,
was examined and testified as follows:
DIRECT EXAMINATION
BY MR. MACDONALD:
MR. MACDONALD: Ms. Hartwick, would you please state your name and address for the record.
MS. HARTWICK: Emily Hartwick, One Riverfront Plaza, 55 Campau Northwest, Grand Rapids, Michigan, 49503.
MR. MACDONALD: And would you please state your relationship to the petitioner and/or its parent?
MS. HARTWICK: I am a geologist with the parent corporation.
MR. MACDONALD: All right. I'm now going to show you what has been marked as Exhibits F, G, I, and K for purposes of this cause. Do you recognize those exhibits?
MS. HARTWICK: Yes, I do.
MR. MACDONALD: And were they prepared by you?
MS. HARTWICK: They were.
MR. MACDONALD: Starting and directing your attention first to Exhibit F, which again is shown for the Board's convenience on the PowerPoint presentation, would you please explain to the Board what this exhibit

represents?

MS. HARTWICK: This exhibit shows a cross section through the Providence field, looking in the northeast direction. And on the cross section, shown on the lower right, it demonstrates the fault bend fold and the horse block that sets up the structural configuration of the field. The Navajo 1 reservoir lies within the fault bend fold, and the Navajo 2 reservoir is subthrust to the Navajo 1 sheet and is a small horse block.

MR. MACDONALD: All right. And the Navajo 1 and Navajo 2 are the two productive zones of interest with respect to the two wells at issue. Is that correct?

MS. HARTWICK: That is correct.

MR. MACDONALD: I now direct your attention to Exhibit G. This is a two-page exhibit. Exhibit G-1 on the first page is reflected, for the Board's convenience, on the PowerPoint behind them.

Would you please explain what Exhibit G-1 represents?

MS. HARTWICK: G-1 represents the log analysis of the Navajo 1 reservoir, and the 24-1 and 24-4 wells. It also shows the parameters that we use to calculate this log analysis.

It is important to point out on this slide, if you can look at the dashed blue line here, this represents the porosity of both of these wells. And you can note that comparing the 24-1 porosity, we have a tight streak in the middle of the pay section, and that is different from what we see in the 24-4 well. This demonstrates the variability of reservoir quality that we see across the field. And in total, in the 24-1 well, we calculated 134 feet of pay; and in the 24-4 well, we calculate 122.5 feet of pay.

MR. MACDONALD: All right. Now directing your attention to Exhibit G-2, would you please explain to the Board what this represents?

MS. HARTWICK: This exhibit shows the log analysis of the Navajo 2 reservoir in the 24-1 well. The 24-4 well did not encounter any Navajo 2 pay. Similar presentation that includes our parameters used to calculate the log analysis, and this analysis results in 95.5 feet of pay in the 24-1 well.

MR. MACDONALD: All right. I would like to direct the Board's attention now to Exhibit H. These are true and correct copies of the administrative approvals by both the BLM and the Division of Oil, Gas and Mining, for the administrative authorization for flaring and venting during testing, which the agencies would allow without having to come for Board approval. And again, I will proffer these into evidence. But this is just to show that the authorization for the flaring and venting through the testing period was allowed by both agencies.

Now, Ms. Hartwick, I'm going to direct your attention to Exhibit I. This, again, is a two-page exhibit.

Starting with Exhibit I-1, would you please explain to the Board what this represents?

MS. HARTWICK: Exhibit I-1 shows the extensive testing of the Navajo 1 reservoir in both the 24-1 and 24-4 wellbores. The way to read this slide is that each perforation set has been designated with a number, and then the details of that perforation set are posted beside that number along the sides of the slide.

We began testing the 24-1 well with perforations in the Navajo 1 reservoir low in the pay section, some of which had very high water cuts. We then moved up in the 24-1 to investigate the presence of a gas cap within the reservoir. And that highest perforation within the porous interval of the Navajo 1 is represented by Perforation No. 4. Based on that test, we do not believe that there is a gas cap within this reservoir.

The 24-4 well was also perforated in the Navajo 1, with several sets of perforations. Again, these perforations that were low in the pay column had high water cuts. Those were squeezed, and we perforated additional sets higher up.

The sets that are marked with No. 3 and No. 4 were subjected to a 61-day flow test. And you can see the results of that flow test in the chart on the bottom of the slide. Along the X axis we have the date, and on the Y axis to the left, we have barrels of oil per day or barrels of water per day. And then the far right Y axis shows the mcf of gas per day.

You can note that the volumes of oil began near the 200 barrels of oil per day mark, but then they fell below 100 barrels of oil per day by the end of the test. And also noted on this chart, as you can see, on the last two days of production our water volumes increased drastically, and we are not sure what the cause of this was. It's a reason of concern for us now.

MR. MACDONALD: That's also a reason why additional testing is going to be required. Is that correct?

MS. HARTWICK: Yes, that is accurate.

MR. MACDONALD: All right. Moving on to --

CHAIRMAN JOHNSON: Mr. MacDonald?

MR. MACDONALD: Yes.

CHAIRMAN JOHNSON: Before you move on, I note that in the handouts, the exhibits that you gave us, the material is laid out a little bit differently than it is in the slide. There's nothing materially different?

MR. MACDONALD: No, there isn't. It was just to make the PowerPoint presentation present better with the layout of the screen, and all that. But the material information is all is same, yes.

CHAIRMAN JOHNSON: Okay. Thank you.

MR. MACDONALD: Directing your attention now to Exhibit I-2, would you please explain to the Board what this represents?

MS. HARTWICK: I-2, again, shows perforated intervals for the Navajo 2 reservoir. And we only have perforations in the 24-1 well in this interval. After finishing the testing of the Navajo 1 reservoir in the 24-1 well, we returned to the Navajo 2 and performed a fracture stimulation, followed by a flow test. The results of that flow test are, again, shown in the chart on the slide.

And you can see that the initial oil rates started out above 500 barrels of oil of a day, but they quickly fell to below 100 barrels of oil within a couple weeks.

MR. MACDONALD: I'd like to bring to the Board's attention that Exhibit I represents a requirement under the regulation for the petitioner to supply to the Board, which would be the initial flow test results. And so these exhibits reflect satisfaction of that criterion as set forth in the regulation. All right.

Like to now direct your attention to what has been marked at Exhibit J. For purposes of this hearing -- again, Mr. Chairman, I'm glad you pointed it out. This is going to appear slightly different on the PowerPoint presentation. But again, the information is the same, it's just a slightly different presentation because of the layout.

But again, would you please identify, starting with Exhibit J-1, what this exhibit represents.

MS. HARTWICK: Exhibit J-1 and J-2 really serve to show the differences between the gas compositions of the two different reservoirs. Exhibit J-1 is a gas analysis from the Navajo 2 interval. And you can see, this gas is composed of 19.9 percent inert gases with 1000 ppm of H_2S.

MR. MACDONALD: And again, just for foundational purposes, Exhibit J was not prepared by you, but it was prepared by Wolverine contractors. Is that correct?

MS. HARTWICK: That is correct.

MR. MACDONALD: And that the exhibits that are presented are actually true and correct copies of Wolverine business records as the contractors provided them to you. Is that correct?

MS. HARTWICK: That is correct.

MR. MACDONALD: Addressing your attention now to Exhibit J-2, would you please explain to the Board what this reflects.

MS. HARTWICK: J-2 is the gas analysis from the Navajo 1 reservoir. You can see the concentrations of different gases are much different from the Navajo 2. The Navajo 1 has 86 percent inert gases, and most of that is carbon dioxide.

There is also 32 ppm of H2S in the Navajo 1 gas, that is shown as a zero on this exhibit due to the sample protocol. But the 32 ppm was measured on-site. You can also see this gas has very low BTU content.

MR. MACDONALD: Again, for the Board's reference, the gas analysis is another regulatory criteria that the petitioners are required to present for flaring and authorization, and that's why this exhibit has been submitted.

Finally, I'm going to direct your attention, Ms. Hartwick, to what has been marked as Exhibit K for purposes of this cause. Would you please explain to the Board what this represents?

MS. HARTWICK: Exhibit K shows our oil-in-place calculations for the Navajo 1 and Navajo 2 reservoirs. These calculations are based on our log analysis, and our structural control from well penetrations, and also the seismic interpretation. Navajo 1 calculates about 10.2 million barrels of oil-in-place. And the Navajo 1 is a low permeability reservoir.

The Navajo 2 has a little over half a million barrels in place, and this is limited in size.

MR. MACDONALD: Mr. Chairman, that concludes my examination of Ms. Hartwick.

CHAIRMAN JOHNSON: Mr. Alder?

MR. ALDER: Just one second.

Yes, Mr. Chairman, the Division has a few questions.

CROSS-EXAMINATION

BY MR. HUNT:

MR. HUNT: Ms. Hartwick, I notice you didn't have an exhibit basically showing the aerial extent of your reservoir. How did you determine that, and what is it, basically?

MS. HARTWICK: The aerial extent of the reservoirs was determined by our seismic mapping and the well penetrations. I'll have to confer with counsel for just a second.

The size of the reservoirs we are holding confidential at this time.

MR. ALDER: So the exhibit that you provided,

Exhibit F, is based on seismic data that you are not providing as part of this petition. Is that correct? That's just a cross section.

MS. HARTWICK: Yes. That is based on seismic that we are not providing.

MR. ALDER: And is any of that information available publicly elsewhere?

MS. HARTWICK: No, not at this time.

MR. MACDONALD: If the Division or Board deems that information crucial to this determination, we can make special in-camera accommodations for that. But the material has to remain proprietary and confidential at this time.

MR. ALDER: So then when we get to Exhibit K and you provide us with the volumes of gas, there's not an exhibit to support that? Was that K or J?

MR. MACDONALD: The exhibit that's appearing -- the hydrocarbon-in-place calculation?

MR. ALDER: Yes.

MR. MACDONALD: That's Exhibit K.

MR. ALDER: And is that information proprietary -- I mean, the source of that information?

MS. HARTWICK: Yeah. The seismic interpretation that we used to create the volumetric use in that calculation is being held confidential.

MR. ALDER: Mr. Chairman, if we might just reserve the right to ask for additional information after we've consulted, maybe after our lunch break. But we have no other questions for this witness.

CHAIRMAN JOHNSON: Thank you, Mr. Alder.

Does the Board have questions for Ms. Hartwick?

MR. HAROUNY: I have a couple of questions for Ms. Hartwick.

In Exhibit I -- sorry, Exhibit F, you show the location of your line A to A prime goes right through 24-1 and 24-4. I believe that's a seismic line going through there. Where is the location -- in the map, you don't show the location of 24-4.

MS. HARTWICK: On the cross section, the well is projected into the cross section, and we are only using the one well in the projection.

MR. HAROUNY: But you have two wells here. So you have two wells on either side of the line, but you only have one well on the map right next to it.

MS. HARTWICK: Yes. And they would project to roughly about the same locations along that line.

MR. HAROUNY: The reason why you don't have the second well on there?

MS. HARTWICK: It was not germane to the creation of the cross section.

MR. HAROUNY: But everything you see here is germane to the difference between -- if you want to get a visual of 24-1 penetrating through a certain zone, Navajo 1, but not present in 24-4, but --

MS. HARTWICK: If I can clarify. The 24-4 did penetrate the Navajo 2 interval. And if we -- I can direct your attention to Exhibit I-2 that shows the test results of the Navajo 2. I've included the 24-4 wellbore on this cross section in order to kind of show the structural differences between the two wells.

The Navajo 2 and the 24-4 well was encountered over 2000 feet low to the 24-1 well. So the Navajo 2 does exist at the 24-4 location. It is just below the oil-water contact and not hydrocarbon bearing.

MR. HAROUNY: So based on what I see on the map right here in Exhibit F, then the locations are not on top of each other. Because if they were, they would end up in the same spot, correct -- on the structure?

MS. HARTWICK: Well yeah, that is correct.

MR. HAROUNY: There are 2000 feet of structural difference, is what you are saying, between one to the other.

MS. HARTWICK: The line of cross section, which is between the two wells -- we're showing the 24-1 well on the cross section. If you were to move that cross section, stepping it down to the southwest, the location of the fault cutoff between the Navajo 1 sheet and that Navajo 2 horse block does come down to provide that structural difference. So to clarify, the 24-4 is not -- not the same as the 24-1 on that cross section.

MR. MACDONALD: If I may ask a clarifying question. I think the intent behind Exhibit F was just to give relevant overall picture of the two structures and the folding that's occurred here. It was not intended as a detailed interpretation of the wells and their logs that was done on Exhibit I, as presented. But this was just to give an overall narrative of how the structure and the relation of the two productive zones appears.

MR. HAROUNY: My point is, then, Mr. MacDonald, that there are two wells, and they are represented on the map, here, but not on this map. So for the purpose of clarity, I wanted to make sure we understand where the 24-4 well was on this side of the map.

I have another question for you, as well, since this is going to be with the first one -- and the Exhibit I. If you go to Exhibit I, please.

You see that your Test No. 4 had over a million cubic feet -- 1.2 million cubic feet of gas per day at a 405-pound of flowing tubing pressure.

CHAIRMAN JOHNSON: That's on the 24-4 well?

MR. HAROUNY: On the Navajo 1, correct.

On the -- your Test No. 3 shows 500 mcf of gas per day. There was no pressure noted in there. And your Test No. 2, getting lower and lower in the section, "Gas not measured." I wonder why that wasn't measured. But Test No. 1 shows no gas. So is it your testimony that this is a gas cap reservoir?

MS. HARTWICK: No, at this time we do not feel there is a gas cap in the reservoir.

MR. HAROUNY: But if you stack them up, the highest gas was noted up on top.

MS. HARTWICK: Also, if you notice, the oil rate was also increasing as you go from 3 to 4.

MR. HAROUNY: So is this a gas solution reservoir, or a waterdrive reservoir.

MS. HARTWICK: I'll have to confer.

MR. MACDONALD: Mr. Zadick will be addressing the reservoir characteristics, Mr. Harouny, if you just defer that question.

MR. HAROUNY: My understanding was that this was not a gas cap reservoir. I have no more questions.

CHAIRMAN JOHNSON: Other questions from the Board?

Mr. Alder.

MR. ALDER: I neglected to ask one question about the exhibits. You testified with regard to Exhibit J that those exhibits were not prepared by you. Were they prepared under your direction?

MS. HARTWICK: Exhibit J, which are the gas analyses were prepared by the companies that performed the gas analyses. Would you like the names of those?

MR. ALDER: No.

And did that same reference, did that refer to any of the other exhibits, or just Exhibits J?

MS. HARTWICK: Only Exhibits J.

MR. ALDER: Thank you.

MR. MACDONALD: Point of clarification, too, Mr. Alder, Exhibit H is true and correct copies of filings that are on file with the Division and the Bureau of Land Management. Those are true and correct copies. Those were not prepared by her, either.

MR. ALDER: Well, you haven't offered those. She didn't testify to those at all. Do you intend to have her to -- or some other witness testify to --

MR. MACDONALD: No. That was it. We proffered it in evidence.

MR. ALDER: I think somebody needs to authenticate those. Is that going to be your testimony?

MR. MACDONALD: Well, if you are going to contest it, then I'll get somebody to testify. It's true and correct copies that are on file with the Division. I didn't think there was going to be an issue with regard to proffering those into evidence.

MR. ALDER: They're not offered at this time, Mr. Chairman, so we can confer.

CHAIRMAN JOHNSON: Say that again, Mr. Alder?

MR. ALDER: Since Mr. MacDonald has not offered these exhibits at this time, maybe he and I can confer about them.

CHAIRMAN JOHNSON: Mr. Harouny, do you have a question?

MR. HAROUNY: I have one last question, and that has to do with Exhibit K. We have some hydrocarbons-in-place, and I believe gas should be in that category -- at least I think so -- but you had no numbers for gas-in-place.

MS. HARTWICK: I did not report gas numbers in-place. That will be something that Mr. Zadick will talk about later, in terms of recovery.

MR. HAROUNY: So is there another exhibit that had gas-in-place numbers?

MS. HARTWICK: There's not another exhibit, but I have those figures here, if you would like those.

MR. HAROUNY: Sure, unless it's part of the testimony that's coming up.

MR. MACDONALD: I don't think it is.

MS. HARTWICK: I don't believe it is addressed later.

MR. HAROUNY: Okay.

MS. HARTWICK: For the Navajo 1 reservoir, assuming a GOR of 5702, and using the oil-in-place number that I have shown above, the total gas reserves in-place is 58.2 bcf. Forty-seven bcf of that 58.2 is carbon dioxide; 3.2 bcf is nitrogen; 3.5 bcf is methane; 1.1 bcf is ethane; and 3.4 are other components.

In the Navajo 2 reservoir, using a GOR of 6726, we have 3.2 bcf total in-place. 2.02 of that is methane; .37 bcf nitrogen; .27 bcf of ethane; and .26 bcf of carbon dioxide; .27 of other components.

MR. HAROUNY: And the methane in the Navajo 1 was 3.1?

MS. HARTWICK: Methane in the Navajo 1 was 3.5 bcf.

MR. HAROUNY: 3.5 -- thank you.

CHAIRMAN JOHNSON: Mr. Gill.

MR. GILL: Yes. If you'd go back to Exhibit F, I just kind of want to have you, if you would, take your red pointer, and on that, where it says that this -- it's structurally the highest sheet in the Providence field, point on the exhibit where you are referring to.

MS. HARTWICK: This package, right here, is the structurally highest sheet, and that contains the Navajo down to some Triassic strata below it. All of this pink interval on the cross section is the Arapien formation.

MR. GILL: It's the what?

MS. HARTWICK: The Arapien formation. And it behaves rather plastically, as you can see in this cross section. The main structural sheets that start to behave more rigidly starts at the Twin Creek Navajo, which is identified by this upper-most yellow part of the sheet.

MR. GILL: Okay. And then their second bullet says, the "Fault-bend fold provides structural closure." You are just talking about a traditional overthrust-type fault situation?

MS. HARTWICK: Yes, the shape of this fold provided by the fault bend, yes.

MR. GILL: And what's the depth between the top of that sheet and the bottom of that sheet, just in general?

MS. HARTWICK: In general, we're looking at -- oh, about 8800 feet at the top of the Navajo 1 sheet. And at the Navajo 2, we're about 12,150. So that's about --

MR. GILL: About 3000 feet?

MS. HARTWICK: About 3000 feet.

MR. GILL: And of that, how much could you consider pay zone?

MS. HARTWICK: In Navajo 1 --

MR. GILL: The Navajo 1, right.

MS. HARTWICK: -- the gross pay zone at the 24-1 location, which is structurally higher, is about 261 feet of gross pay.

MR. GILL: Let's go to the Navajo 2. You say Navajo 2 is a isolated horse block. Would you define how you use "horse block"?

MS. HARTWICK: The horse block represents this little wedge piece of the Navajo and Triassic section. A horse block is generally defined as any block that is bounded on both sides by faults. So the bottom portion of the block has a fault here, and then a fault riding up that brings the Navajo 1 sheet on top of it.

MR. GILL: And then you say the fault seal occurs along the western edge of Navajo 2.

MS. HARTWICK: Yeah. And that fault seal is right along this fault here.

MR. GILL: And did I hear you say that there's a salt dome in this area, or are there salts.

MS. HARTWICK: Their salts present in the Arapien above the Navajo. We do not encounter any

Arapien between the Navajo 1 and Navajo 2. So the only salt that we see is above the top of the Navajo. And I wouldn't call it a "salt dome," it's just salt within the Arapien formation.

MR. GILL: Over time has it flowed?

MS. HARTWICK: Yes. It's geologically relevant to assume that the salt would move, umm-hmm.

MR. GILL: The next exhibit is Exhibit I. And it's just some of the nomenclature you've used. Let's start with the 24-4 perforation summary. On perforation No. 2, the gas was not measured, and then it was -- what's that word?

MS. HARTWICK: "Squeezed."

MR. GILL: Will you define that.

MS. HARTWICK: It means we plugged the perforation holes with cement.

MR. GILL: So they're basically isolated.

MS. HARTWICK: Yes, they are closed.

MR. GILL: Then on the blue line on the log, is left -- which is better, left or right, on that in terms of -- pardon me, the blue line.

MS. HARTWICK: The porosity increases from the right to the left. And I believe the scale on that should be zero to 30 percent. So about the middle of your tract should be about 15 percent.

MR. HAROUNY: You're sure it's not minus 15 to 45.

MS. HARTWICK: If I can look at my paper copies to -- it is difficult to read on the copy that I have. I typically use a scale of zero to 30 in my presentations, so I would be very confident that that's a zero to 30 scale.

MR. HAROUNY: On a 271 matrix?

MS. HARTWICK: No. This would be on a sand matrix, so 2.65.

MR. GILL: And then on Exhibit J, again what interval are we talking about in terms of the test on Exhibit J -- the first page of J?

MS. HARTWICK: The first page of J is for the Navajo 2, so the deeper reservoir. And this analysis came from the 24-1 well.

MR. GILL: So it's about 75 percent carbon gases, carbon-based gases, give or take a bit?

MS. HARTWICK: Yeah. Oh, 80, I think. It's about 20 percent inert gases.

MR. GILL: Then on the Questar -- I used to work for Questar. And I may have a conflict of interest that I need to explore there --

MR. MACDONALD: I don't think it is, Mr. Gill. Not unless you want to challenge the porosity of the test by your former employer.

MR. GILL: Just for everybody's disclosure. That was sometime ago, but -- that's all I have, Mr. Chairman.

CHAIRMAN JOHNSON: Any other questions for Ms. Hartwick?

MR. ALDER: Mr. Chairman.

CHAIRMAN JOHNSON: Mr. Alder.

MR. ALDER: I don't know if -- if the Board would indulge the Division with one more question from Mr. Doucet, we would appreciate it.

CHAIRMAN JOHNSON: So indulged.

MR. ALDER: Thank you.

MR. DOUCET: Just had a clarifying question on your testimony on the gas-in-place portion. You gave some gas-oil ratio numbers for the Navajo 1 and Navajo 2. And as I jotted them down -- hopefully I didn't jot them down wrong -- but you had stated the gas-oil ratio for Navajo 1 is 5702. Is that correct?

MS. HARTWICK: That's correct.

MR. HUNT: And Navajo 2, gas-oil ratio is 60, 70 and 26.

MS. HARTWICK: That's correct.

MR. HUNT: As I looked at the Request for Agency Action, on page 4 paragraph 7(b), it appears that those numbers are reversed in there, unless I'm reading that wrong. I believe it states in there that the 24-1 was tested in both the Navajo 1 and 2, with the wells currently completed only in the Navajo 2 with a gas-oil ratio of 5702. I skipped a few parts in there, but essentially that's what it said.

And then the 24-4 well was completed and tested in Navajo 1, skipping a little, with the gas-oil ratio of 6726. Same numbers, but it would be referencing the different Navajos.

MS. HARTWICK: I do see the conflict there.

MR. MACDONALD: If we could take a second.

MR. ALDER: I notice she's referring to an exhibit. Is that an exhibit you did not want to make part of the record, or can we make that part of the record?

MR. MACDONALD: She's testified to it. It wasn't intended as an exhibit. If we could confer, Mr. Chairman, just a minute to clarify that. I see where the confusion lies in that. I don't know if that lies with me and my typing, or if there's a true discrepancy there between her testimony --

CHAIRMAN JOHNSON: Go ahead.

MR. MACDONALD: Thank you.

Mr. Chairman, maybe in the interest of time, we're going to have to double check that. And we will confirm which GORs are correct, and clarify the statement and confirm to that.

CHAIRMAN JOHNSON: Okay. We'll probably be taking a break for lunch after Ms. Hartwick is through, so --

MR. MACDONALD: We'll get that clarified, then, before we get back on the record.

CHAIRMAN JOHNSON: Okay.

MR. MACDONALD: And we will conform the Request to whatever the proper numbers are. We're trying to determine if it was a mistake made in the Request application, or if it was just in Ms. Hartwick's testimony.

CHAIRMAN JOHNSON: Okay.

Mr. Alder?

MR. ALDER: No other questions.

CHAIRMAN JOHNSON: No other questions.

MR. HAROUNY: One last question that I have.

Is this -- have you flared the gas? Is this a burnable gas, does it burn because of the high C02 content?

MS. HARTWICK: I do not believe the Navajo 1 gas --

MR. HIGUERA: I'll be addressing that in my part.

MR. HAROUNY: Okay.

CHAIRMAN JOHNSON: Any other questions for Ms. Hartwick? I think we're through with Ms. Hartwick.

Seeing that it's now about 12:20, why don't we take a break for lunch. And let's plan to reconvene at 1:30. Does that give everyone enough time? Thank you very much.

(A break was taken from to 1:33 p.m.)

CHAIRMAN JOHNSON: Go ahead, Mr. MacDonald.

MR. MACDONALD: Thank you, Mr. Chairman. Before we dismiss Ms. Hartwick, she'd like to take an opportunity to respond and correct a testimony, both to Mr. Doucet's question regarding the discrepancies of the GORs and also Mr. Harouny's question regarding the gas-in-place numbers.

CHAIRMAN JOHNSON: Okay. Go ahead.

MS. HARTWICK: The GORs that are listed in the request are accurate. And they reflect a producing GOR based on the well performance. I would like to correct the gas-in-place numbers that I reported, because those gas-in-place values should be calculated using a GOR coming from PVT analyses. And I would like to revise those numbers now, at this time.

For the Navajo 1, the GOR from PVT analyses is

2975. You'll notice that this is different from the GOR listed in the Request, and Mr. Zadick is going to speak to the complexity of the fluid system and why these GORs are variable. But using the appropriate GOR of 2975 for the Navajo 1 reservoir, the gas-in-place is 30.3 bcf total; 24.5 bcf of that gas in the Navajo 1 is carbon dioxide; 1.7 bcf is nitrogen; 1.8 bcf is methane; 0.6 is ethane, with the remainder being other components.

For the Navajo 2 gas-in-place numbers, the appropriate GOR, again from PVT analyses to calculated oil and -- excuse me -- the gas-in-place reserves, is a GOR of 2380. That gives us 1.3 bcf of gas-in-place for the Navajo 2 reservoir; 0.8 bcf of that amount is methane, 0.15 bcf is nitrogen, 0.1 bcf is ethane, and 0.1 bcf is carbon dioxide, with the reminder being other components.

CHAIRMAN JOHNSON: And I don't believe those numbers were reported on any of the exhibits.

MR. MACDONALD: No, they weren't, Mr. Johnson. Just the oil-in-place was. But based on Mr. Harouny's question, Ms. Hartwick was trying to answer that.

CHAIRMAN JOHNSON: So there's no exhibits that need to be changed to reflect that?

MR. MACDONALD: No, there are not. And the Request, as stated, is correct on the GOR, with the understanding that's the producing GOR.

MR. HAROUNY: What was the difference in correction -- what was corrected -- what was corrected here to bring the GORs down by literally half or more?

MS. HARTWICK: The GOR from the PVT analysis comes from a certain production scenario that was in the test. Those scenarios are different from the wellbore conditions right now. And Mr. Zadick can speak to that in a moment.

CHAIRMAN JOHNSON: Mr. Alder, any questions?

MR. ALDER: That satisfies the Division.

MR. MACDONALD: Thank you for pointing that out, too, Mr. Doucet -- the discrepancy.

CHAIRMAN JOHNSON: I don't think anyone else has questions for Ms. Hartwick. Is that correct?

So I think we're through with Ms. Hartwick. Thank you very much.

MR. MACDONALD: Thank you, Mr. Chairman. We'll commence with our examination of Mr. Zadick.

THOMAS W. ZADICK,

having been first duly sworn,

was examined and testified as follows:

DIRECT EXAMINATION

BY MR. MACDONALD:

MR. MACDONALD: Mr. Zadick, please state your name and address for the record.

MR. ZADICK: Thomas W. Zadick. Address: 4904 Melrose Park Drive, Colleyville, Texas, 76034.

MR. MACDONALD: Would you please state your relationship to the petitioner and to its parent corporation?

MR. ZADICK: I'm a consulting engineer, specializing in reservoir engineering and enhanced oil recovery, working for Wolverine.

MR. MACDONALD: I'm going to now show you what has been marked as Exhibits L through O, substitute Exhibit P, and Exhibit Q. I ask: Do you recognize all those exhibits?

MR. ZADICK: Yes, I do.

MR. MACDONALD: And were they prepared by you or Wolverine personnel with your input and review?

MR. ZADICK: That is correct.

MR. MACDONALD: Would you please provide some introductory comments regarding your testimony of the modeling that was utilized here.

MR. ZADICK: Okay. Could we turn to...

MR. MACDONALD: Yeah. Let's turn to Exhibit L, first.

MR. ZADICK: Thank you. The model was constructed -- is three dimensional, three phase, finite difference simulator, and it incorporated the geological and petrophysical input that you've heard supplied by the Wolverine studies. The model has relatively course grids. In the aerial sense, there are 22 by 29 grid locks and three layers vertically. Most all of the hydrocarbon system is in the upper two layers. The oil-in-place in the model is a little over 10 million barrels, with a little over 30 bcf gas. The model is constructed solely for the Navajo 1 reservoir. And the Navajo 1 is -- model is being an active waterdrive reservoir by incorporating constant pressure, water injection wells around the perimeter of the hydrocarbon trap, such that pressure will be maintained below the oil-water contact.

The horizontal permeability in the model was adjusted to incorporate data from well test analysis. And the permeability average is less than 1/2 a millidarcy. This is much lower -- on the order of one to two orders of magnitude lower -- than what we see in the Nugget reservoir in the Overthrust fields, or in the Navajo reservoir in the Covenant.

Our objective in doing this modeling was to determine if additional drilling and/or gas injection could be justified by the incremental recovery resulting from such activities. And as such, we tried to incorporate as many optimistic assumptions about the model as was possible, in order to model these processes. So the oil recovery relative to both water displacement and gas displacement was looked at in an optimistic fashion.

In addition, we assumed that the wells would be recompleted and that all of the porous intervals above the original oil-water contact would be perforated and stimulated to remove any damage. As such, the initial producing rates in the model were well above what we observed in the initial well tests.

Two cases are presented today. The first is a case where both wells, the 24-1 and the 24-4, are producing. In the second case, the 24-4 is converted to injection, and the 24-1 continues to produce.

MR. MACDONALD: Mr. Chairman, before we move on, I want to point out, similar to some of the other exhibits the PowerPoint presentation may look a little different for the layout purposes, but there's no material changes from the exhibits that we submitted to the Board.

CHAIRMAN JOHNSON: Okay. Thank you.

MR. MACDONALD: Moving on now to Exhibit M. This is a two-page exhibit. Starting with Exhibit M-1, would you please explain what this represents?

MR. ZADICK: This first exhibit has the oil-water relative permeability and the capillary pressure that was used to initialize the model. Shown on the left is the oil-water relative permeability. This is just a measurement that tells us how the two fluids will flow relative to one another in a two-phase system.

So on the left is -- on the Y axis is relative permeability, and on the X axis is water saturation. The red curve is oil permeability. So as water saturation increases, the oil permeability drops. And the blue curve is water relative permeability. And as water saturation increases, the water relative permeability also increases.

This data was taken from core work that was done on Covenant field, and normalized so that it could be utilized at Providence. Now two things are different about Providence. First, the connate water saturation is much higher. So we had to adjust this end-point value, right here, to reflect an initial saturation of about 35 percent.

Secondly, the point at which the oil permeability drops to zero is the point at which oil saturation is trapped in the reservoir. And since this is a two-phase system, the oil saturation that's indicative at this point is just one minus the water saturation. So it's about 30 percent.

This is identical to the value that was utilized, or that was determined for the Covenant core work. But -- and one could argue that because Providence is so much lower permeability than Covenant, that perhaps the residual oil saturation must be set at a much higher value. But this would reduce the amount of mobile oil saturation. It's present in the model. And in order to keep the results optimistic, we decided to leave this value alone.

The capillary pressure curve was used to initialize the water saturation in the model. And it also governs the water saturation that is present as the aquifer encroaches.

MR. MACDONALD: Right now, directing your attention to the second page of Exhibit M, M-2, would you please explain what this represents.

MR. ZADICK: Yes. The second page is the gas liquid relative permeability. Here, liquid refers to the sum of both oil and water saturation. So again, on the left, we have gas liquid relative permeability. The Y axis is the relative permeability measurement. The X axis is the total liquid saturation. The red curve is the gas saturation, so as liquid saturation increases, the relative permeability of the gas drops. There's a trapped residual saturation of about three percent.

The curve in blue is the liquid relative permeability. And as liquid saturation increases, the liquid permeability also increases. There were no gas/liquid relative permeability measurements available on the Navajo reservoir. So this data was normalized from the Nugget in the Utah/Wyoming overthrust portion and brought over to use here.

Now there are two things that I want to point out about this curve. First is, the trapped gas saturation is set very low. The second is that there's a point here where the liquid permeability goes to zero, the gas permeability continues to increase until you've reached the connate water saturation of 35 percent. And the difference in these two values is about 10 percent. So the trapped oil saturation in the model is about 10 percent of the total pore volume; whereas, with water displacing oil, the trapped saturation is 30 percent. So this makes the model relatively optimistic towards a gas displacement process.

Also notice that the end point values for relative permeability for both liquid and gas are set quite high, and that the shape of the curve is quite linear. This linear shape is what you would expect for a miscible process. And we decided to use these values in order to try to get as much oil recovery from the model during gas injection. Also notice that the gas liquid capillary pressure is set to zero, so there is no transition zone at all.

MR. MACDONALD: Moving on to Exhibit N. Would you please explain to the Board what this exhibit represents.

MR. ZADICK: Yes. Exhibit N is a summary of the fluid data from two different laboratory tests -- one done by Fesco, shown in blue, and the other done by CoreLab, shown in red. The curve on the left is Rs, or the amount of solution gas present in the oil as a function of pressure. The curve on right -- on the right is a thing that we call the formation volume factor. And it's an indication of how much shrinkage we're going to incur as the oil is brought up from reservoir conditions to surface conditions.

Now, starting with the curve on the left, notice that the differential liberation gas-oil ratio is a little over 4000 standard cubic feet per barrel. The sample proved to be an undersaturated oil, with a bubble point pressure of 3485. So it's very close to initial reservoir pressure. And when this value -- when the differential liberation endpoint is corrected for separator conditions, a separator -- the combined GOR drops to a value of 2975. And that's the GOR that Emily used in correcting her gas-in-place estimate.

And for clarification, all of the modeling work was done utilizing the CoreLab result. It just looked more consistent and did a much better job at close to initial reservoir pressure. The Bo -- similarly the Bo is a little over 3. So that means that for every reservoir barrel of oil that we produce, we're only going to realize a third of a reservoir barrel at surface conditions. But when we correct these values for separator conditions, the combined Bo is a little over two point -- is a little under 2.7. And that's also the value that Emily used in estimating oil-in-place numbers.

MR. HAROUNY: These numbers are derived from the Navajo?

MR. ZADICK: From the Navajo 1 oil samples taken on 24-1, and two different laboratory tests, CoreLab and Fesco.

MR. HAROUNY: But the previous things were just brought in from Nugget production to the north, basically?

MR. ZADICK: Just the gas-liquid relative permeability curves. The oil-water relative permeability curves were brought in from Covenant.

MR. HAROUNY: Okay. So this is all oil, not gas, you are talking about, basically.

MR. ZADICK: This is an undersaturated oil reservoir, that's correct, but extremely volatile. It has a very, very high GOR for an oil system.

MR. HAROUNY: In your calculation for gas-in-place, what numbers did you use there?

MR. ZADICK: The model has 30 BCF.

MR. HAROUNY: What numbers did you use in your gas calculations? Did you use the Covenant field numbers, or did you use the well numbers for gas calculation? Where did you extrapolate for your data base points?

MR. ZADICK: The gas-in-place numbers are calculated using the CoreLab results, utilizing the combined separator differential liberation Rs from Providence field, the 24-1 well.

MR. HAROUNY: Okay.

MR. ZADICK: So because this is such a volatile oil system, what happens is that as we produce the Navajo reservoir, we very quickly see a drop in pressure below the bubble point pressure. And when this happens, gas starts to come out a solution, just like when you pop the cap on a soda. Within the first year of production, the gas saturations in Layer 1 increase very dramatically. The GOR in the producing well increases from a little under 3000 standard cubic feet per barrel to over 8000 standard cubic feet per barrel.

And the saturation in some of the gridlocks -- the gas saturation in some of the gridlocks in the first year of production increases as high as 27 percent. This 27 percent, if you recall the gas liquid relative permeability curves, results in a reduction in liquid permeability of over 75 percent. So this restricts the amount of oil that can flow in the reservoir.

Now with time what's going to happen is, as the aquifer is able to supply more pressure to the interior of the reservoir, pressure will start to increase, especially as oil-producing rates go down. And as that happens, then more gas goes back into solution. And as more gas goes back into solution, the producing GOR goes down. In the model it takes two to three years for the aquifer to start catching up with the dynamic decline that's occurring in the interior of the reservoir. And that's exactly the explanation for what we're seeing in the producing tests.

If you look at the producing tests, the gas-oil ratios are increasing throughout the test. And the initial GORs that are reported are much higher than what we're seeing from the initial fluid samples in the laboratory data.

MR. HAROUNY: Excuse me, may I?

CHAIRMAN JOHNSON: Go ahead.

MR. HAROUNY: You said that the GORs were -- the number that you got was from the lab samples?

MR. ZADICK: Yes.

MR. HAROUNY: Was it "Core Samples"?

MR. ZADICK: "CoreLab."

MR. HAROUNY: CoreLab.

MR. ZADICK: They're a fluid laboratory. It's a Division of CoreLab, the actual people that do the core analysis work on cores.

MR. HAROUNY: Correct.

MR. ZADICK: They also have a fluid division that does measure -- it's PVT measurements of oil samples. And these are the kinds of numbers that we need to populate our reservoirs.

MR. HAROUNY: Are these in situ numbers, or were the samples exposed at any time to gas escape, at all?

MR. ZADICK: Samples were taken at the surface and recombined into producing GOR that was measured. And the reason for that was it was much too volatile of a system to try to take a sub surface sample.

MR. HAROUNY: So there could be some gas loss due to --

MR. ZADICK: Recombinations were done by two different labs. And there is a little bit of discrepancy in their results, and it's a result of the volatility of the oil. We chose to go with the CoreLab results, which give us a much more optimistic forecast of oil recovery for the reservoir.

MR. MACDONALD: Now, directing your attention to Exhibit O. Would you please explain to the Board the significance of this exhibit.

MR. ZADICK: This exhibit is the measured oil density and viscosity from these same two laboratory measurements. And on the left is oil density. Again, the blue is Fesco, the red is CoreLab. This is density measurements in grams per cc and pressure.

On the right is oil viscosity. And, of course, viscosity is important because it gives us an indication of how relatively easy it is for oil to flow through the porous system. And again, it's plotted versus pressure.

There are a couple of points that need to be made about these curves, relative to the system that we have in Providence. First off, the oil density at reservoir conditions is about .69 grams per cc. And so oil is much lighter than water at reservoir conditions.

However, the solution gas is -- at Providence is composed of a high percentage of carbon dioxide. Because of that, the density of the solution gas is closer to that of oil than you would normally expect if it was a solution gas comprised primarily of methane. So carbon dioxide is heavier than methane, and it ends up having a density at reservoir conditions about 1 1/2 times greater than that of air.

Similarly with the viscosity, the oil viscosity is -- having trouble reading the curve from here -- but it's a little bit under .6 centipoise. When we look at the viscosity of the solution gas with all the carbon dioxide that we have, it's much higher than what you would expect for a normal solution gas, and that's because of the presence of the carbon dioxide.

Now, both of these effects make the gas-liquid system much less gravity stable than what you would expect for a normal solution gas system. And because it's less stable, less gravity stable, the recoveries to gas displacement are hindered. So part of the problem we're having in the modeling is that we're not gravity stable, and that hurts the efficiency of a gas injection project.

MR. MACDONALD: Now, I'm going to refer you to Substitute Exhibit P, which is a two-page exhibit. The first page, P-1, is shown on the PowerPoint behind the Board. Would you please explain the significance of this exhibit?

MR. ZADICK: Yes. This is a collage of curves that I like to look at when I'm evaluating a well test -- a pressure transient analysis test. And there are four plots shown here. But for the purposes today, and then over -- well actually, there are four plots and then the results. So some arise over in the right-hand corner.

And for the purposes today, I'm just going to focus on the upper two plots. The first one is titled a "History Plot." And this curve is a -- segmented into two parts. The lower part shows in yellow the producing rate of the well prior to the shut-in, versus time. So at this point here, the well is shut-in; and as the well is shut-in, we see the increasing pressure on the upper portion of the curve.

The green symbols are the actual measured data from the pressure bomb that was set down at the perforations. There's a more faint red curve that is the actual model results, that are calculated by the model.

So what happens is, we're producing along, we shut-in the well, we see this increasing pressure trend. We can see that the model does a reasonable job of calculating both the flowing pressure and the shut-in pressure during the buildup.

The curve over on the left is the log-log plot. It's plotting the log rhythm of shut-in time, Delta T, versus the log rhythm of Delta P. And in this case, Delta P is the shut-in pressure minus the final flowing pressure.

So the green data on this curve are the actual measured points of the plot. The white line is the model match. The red curve is a mathematical manipulation that reservoir engineers like to look at in order to get a better understanding of what's going on during the buildup. And what this curve is, is the rate of change of Delta P with respect to Delta T. This is commonly referred to as the "derivative plot."

And what we see from this log-log plot are three things. No. 1, the amount of time required for the well to build up relative to the viscosity of the fluids that we're dealing with, is fairly long.

No. 2, the derivative curve shows a downward trend, which is an indication that the reservoir has some complex issues. And in this case, it was interpreted as being a layered system with drastically different porosity and permeability.

The third thing that is shown is there is about 1 1/2 cycles in separation between the derivative curve and the pressure curve. And this is an indication that the well is damaged.

When you take all these things into account, the total permeability thickness is about 20.4 millidarcy feet. So on average, the permeability in the 24-1 during this test period is calculated to be .2 millidarcies. And as I said earlier, this is in comparison to permeabilities at Covenant that measure in the hundreds of millidarcies. I think that's everything on this slide.

MR. MACDONALD: Okay. Now directing your attention to Substitute Exhibit P-2. This is a similar type of exhibit, but relates to the 24-4 well. Would you please explain its significance to the Board?

MR. ZADICK: The significance of this plot is basically that -- the 24-4, we also had a well test. In the case of the 24-4, the actual flowing rate was a little bit higher and peaked at about 200 barrels per day. The well was shut in here. We had a very steep buildup, very sharp transition.

And if we focus on the log-log plot, what we see here is the same downward trend in the derivative curve, further indicating that we are dealing with possibly a layered system, and a lot more separation between the pressure curve and the derivative curve, indicating that this wellbore is severely damaged. So in the modeling work, we did mathematical manipulations to remove this damage and to improve the productivity of the wellbore, assuming that all the porous intervals above the gas-oil contact would be perforated.

MR. MACDONALD: Directing your attention to what's been marked as Exhibit Q, which outlines your conclusions and recommendations. Would you please advise the Board on that?

MR. ZADICK: Yes. Basically, for the two cases being presented, the first case shows with two producing wells, in ten years we're going to expect recovery of about a million barrels of oil. If we turn around and convert one of the wells to gas injection and we're left with only one producer, we still produce about 900,000 barrels of oil in that same ten-year period. But the downside of it is there's only one producing well. So even though the gas injection is beneficial, because we're left with one producing well the process is slowed down.

The recoveries from the modeling work do not support additional drilling. It just economically cannot be justified. So what we're left with is dealing with the two wells that we have. And what we're recommending and asking for is that we be granted a period of time to do additional testing and subsequent modeling. There are a lot of assumptions that have gone into this model, and these assumptions need to be refined, but it will take additional testing in order to come up with refinements. For example, is the gridlock size sufficient, or does it need to be smaller because of the very low permeabilities encountered in this reservoir?

As Emily pointed out, there are indications of strong stratigraphic complexity in the logs. And the model doesn't have any stratigraphic complexity, or any kind of barriers to flow built into it.

What we would like to look at over a period of time is whether we can recomplete the wells; get the kind of initial producing rate that we saw in the model; see that increasing gas-oil ratio trend -- hopefully the water production will not be onerous; and then with time, we'd like to see at what point in time the aquifer is able to start supplying pressure to the interior portion of the reservoir.

With all of these things falling in place, we might be able to refine the model to the point where we can either justify additional drilling or feel more comfortable going forward with gas injection. But the only way to do it, at this point, is to get additional production.

MR. JENSEN: May I ask a question, Mr. Chairman?

CHAIRMAN JOHNSON: Yes.

MR. JENSEN: Do I understand, then, from Exhibit

Q, that the difference between two wells and one well is 60,000 barrels of oil -- 970 as against 910?

MR. ZADICK: That's correct. In ten years, in a ten-year period of time.

And what's happening there is it's a combination of two things: A very high gas saturation; it builds up initially in layer one and reduces the liquid permeability. And the second thing is the fact that we're, you know, we're trading apples for oranges. We're getting the gas displacement benefits that we would like to see, but we only have one producing well to capture it.

MR. HAROUNY: May I?

CHAIRMAN JOHNSON: Go ahead.

MR. HAROUNY: As I remember, this has a high CO2 content -- this gas does.

MR. ZADICK: That's correct.

MR. HAROUNY: And it's miscible, pretty much, is what you're saying.

MR. ZADICK: It was modeled as being miscible with respect to the gas that we reinjected; that is, the produced gas that we reinjected or close to miscible.

MR. HAROUNY: Correct.

MR. ZADICK: If you were introducing the gas back into the formation and you were getting almost twice as much performance out of an existing well, if you were to divide the .97 STB over the two wells, you will end up with a little over 450-, 460,000 barrels per well. But with one well and gas injection you are getting .91 million standard barrels for one well -- from one well with gas injection. So clearly, the gas injection is benefiting each scenario.

So the optimum -- this is just like the Minnelusa wells, or anything like that, where you just create a pressure maintenance program based on miscible gas, and drill out the reservoir. Because at 450,000 or 460,000 barrels per well, clearly you don't need to drill more wells to figure out if it's economic or not. It's showing you that you are getting almost the benefit of 100 percent. You're getting huge matrix contribution based on gas injection.

MR. ZADICK: I'm sorry, I missed the question.

MR. HAROUNY: The question is that -- that this clearly shows that gas injection is beneficial.

MR. ZADICK: We tried to construct the model so that gas injection would be beneficial. We don't know that this is reality. We want to test that and see, you know, with further testing.

Now, it is true that we did recover 900,000 barrels from one well by doing the gas cycling project. However, the problem is, is that the incremental costs -- and Ed will address this a little later -- but the incremental costs involved in setting up the injection -- reinjection project cannot be paid for with the small amount of incremental oil that we're getting.

MR. HAROUNY: Would this small amount of incremental oil be almost 100 percent more?

MR. ZADICK: For one well.

MR. HAROUNY: What would that be over the entire reservoir? We don't know the size of the reservoir, so it could be a two-well reservoir, could be a five-well reservoir.

MR. ZADICK: We're assuming we know the size of the reservoir when we constructed the model. One of the things we'd like to know is if our reservoir size is anywhere close to real. That's why we want to do more testing. And unfortunately -- I mean, if we go in and retest these wells and we find from Day 1 that hey, we can't get any more rate out of these wells, that will give us a very quick answer to our request for additional information. But in order to see the point in time where you actually see the transition from a depletion-dominated system in the interior of the reservoir to aquifer support, that may take much longer, on the order of maybe two to three years, if the model is correct.

MR. HAROUNY: What is the payout -- barrel payout? Would 75,000 barrels or 50,000 barrels be enough to drill a well?

MR. ZADICK: Ed will address those numbers.

MR. HAROUNY: My understanding, initially, was that -- I thought I heard you, that says -- that based on -- on stability of certain factors -- I don't recall what you were referring to -- that this reservoir does not justify ejecting the gas, or it's not a good candidate for injection.

MR. ZADICK: What I said was that if it were gravity stable, it would do much better. Because of the fact that the density of the oil and the density of the gas system are quite close because of the high concentration of CO_2, we have a reservoir that's acting like it's viscous dominated, and that hurts the overall recovery process for gas injection. It doesn't mean it's not going work at all, it just means it's not working as efficiently as we would have hoped.

MR. HAROUNY: Clearly it works to the tune of almost 90 percent or 100 percent, because you're getting -- with gas injection, you're getting almost the same amount of oil out of one well as you would out of two wells, so.

CHAIRMAN JOHNSON: Mr. MacDonald, have you finished with your questions for Mr. Zadick?

MR. MACDONALD: Yes. This is the end of his examination.

CHAIRMAN JOHNSON: Okay.

Mr. Alder, does the State have questions?

MR. ALDER: Yes, Mr. Chairman. Mr. Doucet has some questions for the witness, if that will be allowed.

CROSS-EXAMINATION

BY MR. DOUCET:

MR. DOUCET: Dustin Doucet, petroleum engineer for the Division. I've got a whole list of questions here, I guess. Hopefully we can get through them fairly quickly.

You may have mentioned this a little bit earlier, but what type of reservoir are we dealing with in the Navajo 1, exactly?

MR. ZADICK: Yeah. Go back to the exhibit that shows the Rs and Bo. Dustin, what we're dealing with is a very volatile, undersaturated oil.

MR. GILL: What's the exhibit number, Fred?

MR. MACDONALD: Give me a sec. I think it's N, Exhibit N. N as in Nancy.

MR. ZADICK: So at reservoir conditions -- did you get it Ruland?

MR. GILL: Getting there. I'm there.

MR. ZADICK: What this is telling us is that both oil samples evaluated by Fesco and CoreLab were liquid at reservoir conditions. And yet there was about 100 to 250 pounds PSI difference in the bubble point pressure and the initial reservoir pressure. So both of those -- both of those conclusions, or those measurements, indicate that we have a single-phase oil system up to where we think the structurally highest point is in the Navajo reservoir. So we think we're dealing with a single-phase oil, it's extremely volatile. I would call it a critical fluid, certainly. And because it's so volatile and because we have such a low permeability reservoir, when the pressure drops below the bubble point, gas evolves quickly and the gas saturation in the model builds very fast. Okay.

MR. DOUCET: That kind of leads to my next question. So does your model take into account how the CO2 plays into this equation -- especially when you drop below that bubble point and you start liberating more gas? And what is the condition of the CO2 in the reservoir currently, and how would that react as you go through dropping that pressure in production, in time?

MR. ZADICK: That's a very interesting question.

As Emily alluded to in one of her slides, the CO_2 content in this gas is about 85 percent. There are -- there is a small amount of methane and ethane in the gas that would be detrimental to first-contact miscibility -- if that's where you're heading. We did not model this as being a first-contact miscible CO_2 process. But the gas liquid curves that we put in were so linear that, in effect, it's behaving almost miscible anyway. We were trying to be very optimistic as to the ability of the gas -- the gas to displace oil.

MR. DOUCET: So you would expect that 80 percent CO_2 content to remain fairly constant, as far as CO_2 content in the gas?

MR. ZADICK: Are you asking, with or without injection?

MR. DOUCET: Without injection.

MR. ZADICK: We would expect, yeah, that with time, at least in the model, solution gas is solution gas. So the composition of the solution gas doesn't change over time.

MR. DOUCET: What is the API gravity of the oil in question, of Navajo 1?

MR. ZADICK: I'd have to go to my notes to find that. Ed tells me it's 41.

MR. DOUCET: Okay.

MR. ZADICK: I will point out that the API gravity is related to oil density. And the oil density is shown on the next slide. So, I mean, you can calculate it if you want.

MR. DOUCET: What is the color of the oil being produced?

MR. HIGUERA: Looks like orange juice.

MR. DOUCET: I have a couple more questions. Just X-ing out a couple.

During -- I guess this extended testing that you are asking for, would limiting the -- would limiting the gas-oil ratio or production result in greater ultimate recovery? What kind of damage could be done if we end up flaring too much of this gas or venting too much of this gas and it's not reinjected into the reservoir? Say we start dropping below the bubble point.

MR. ZADICK: Well, if you look at the last slide -- which was Q, I think -- the ten-year recovery isn't really impacted. The two cases shown here, the first case, all of the oil is -- all of the gas that is produced is, in effect, vented. The second case, the solution gas plus the stock tank vapors are reinjected. So the produced gas, the overhead from the separator, plus the stock tank vapors are reinjected. And you can see that the recoveries are basically a push over ten years.

MR. DOUCET: As Mr. Harouny has pointed out, that second scenario was out of one well. So if you drilled another well in that scenario where you were reinjecting, would you expect that to double again -- another one with 910,000 barrels of oil recovery?

MR. ZADICK: Can I confer for a second?

MR. DOUCET: Sure.

MR. ZADICK: I wasn't prepared to discuss other cases that we ran. These aren't the only cases that we ran. We did run cases where we drilled additional wells. We ran one case where we drilled just one additional well. We ran several cases where we looked at less optimistic relative permeability curves.

The bottom line is that if we drill one additional well and convert one well to an injection, we recover additional oil, but not nearly enough additional oil to warrant the costs of drilling that well. In fact, it was only on the order of a small amount higher -- 100,000 barrels or less.

Ed tells me that there's one other point of clarification that I need to make. I said that both fluid samples were collected at the surface. The Fesco samples were collected at the surface, but the CoreLab sample that we utilized was a bottom hole sample.

MR. DOUCET: Part of my concern, I guess, is once -- I guess what I'm trying to get at is, once you drop below that bubble point pressure and you start vaporizing, your oil starts turning to gas. Then you are flaring more and more of your reservoir. So is that going to be detrimental? I mean, you are basically wasting some of the reservoir at that point in time.

And maybe -- another question I had that may go in line with this is: The waterdrive that you mentioned, and what kind of support is that going to give, and what kind of pressure -- waterdrive -- are you expecting on this? Is it going to keep it above bubble point, or?

MR. ZADICK: You know, the initial testing that we did on the wells showed that the wells are falling below the bubble point very quickly. And I'm sure that if I went to a much finer gridded model, I would see more of that kind of behavior.

Your point about flaring solution gas is well taken, except for the gas that we're flaring is 85 percent inerts. So I mean, we're not really giving up a lot of hydrocarbon value in that situation.

In terms of reservoir energy, the aquifer is modeled with constant pressure injection wells that are completed below the oil-water contact around the perimeter of the hydrocarbon trap. Because the reservoir is so tight, it takes a while for the support of that aquifer to get into the interior of the reservoir where the wells are completed. In the modeling work, it takes a year -- more than a year, more like two to three years -- for that effect to start showing a declining gas-oil ratio situation. Does that answer your question?

MR. DOUCET: Yeah. You mentioned -- maybe a little further follow-up on that.

On this -- if this is a near critical and you are dropping below the bubble point, any liquid that's in the reservoir is going to start rapidly changing to gas. So you are losing part of your reservoir, are you not?

MR. ZADICK: Well --

MR. DOUCET: Of hydrocarbon?

MR. ZADICK: It's changing the gas when you produce it up the tubing string, also. That's why the Bo is so high -- the formation volume factor. You know, it's approaching three.

MR. DOUCET: And you'd mentioned additional testing and whatnot. Is there any specific things that you can -- I think you mentioned that you wanted to recomplete the well to see if you can get some comparable rates. Is there any additional specific tests that you are looking at doing? And what exactly would you hope to get out of those tests? And how is that different from what you've done to date, testing wise?

MR. ZADICK: I think we would break the testing down into a series of phases, depending on what we learn as we're going through them. I think the first phase would be to recomplete the wells, restimulate them. We possibly might need to squeeze off one of the wells, based on that water production that we saw at the end of the test on 24-4.

But if we're successful in establishing encouraging rates with the recompletion work, then we would go to Phase 2. In Phase 2 I envision several things happening. One is, we will either try to take downhole pressure measurements in the tubing string to get a good indication of what the bottom hole flowing pressure is and to try to get a better continuous well test using normalized rate-time analysis.

The other thing that I would like to do is to see more buildup tests, but to have incorporated into those buildup tests a much deeper radius of investigation so that we see -- if there are complexities in this reservoir, we need to see whether or not those boundaries show up in the pressure transient work. And to do this, we need to have more cumulative production from the wells.

Of course, it doesn't make sense to do this kind of work if we recomplete the wells and they produce just like they did initially. But if we get encouragement, then those are two of the things that I would like to do.

If we're going to drill additional wells -- if we see enough encouragement to drill additional wells, I would very much like to get some cores in the Navajo 1 and do some special core analysis.

Finally, from the gas-oil ratio and water-oil ratio performance that we get, we can construct models that will more adequately reflect what we're observing in these long-term tests and give us a better picture of what's going on in the reservoir.

MR. DOUCET: Okay. Thanks. What length of time do you think you're looking at to get all that accomplished, should everything go according to plan?

MR. ZADICK: Again, I think Phase 1 we would learn fairly quickly, maybe on the order of however much time it takes to do the surface modifications, put in the facilities, and recomplete the wells, and test them.

Phase 2, in my estimation, depending on how much of it we attempt and whether we try to produce the wells to the point where we're starting to see support from the aquifer, I would say that maybe the outer boundary for that number might be on the order of three years. So the testing, in my mind, would be somewhere between -- the testing period would be somewhere between a few months and three years.

Now certainly I think during the course of this work, if we see things that we learn, we're going to be getting back to the Division and saying, you know, "Hey, this is what we're finding out," and, you know, if we see something that looks disastrous, then the test is over. If we see things that are encouraging and you give us the ability to go ahead to test out to where we're seeing the contribution of the aquifer, that might be a three-year period of time.

MR. DOUCET: Okay. I think that's all the questions I have.

CHAIRMAN JOHNSON: Mr. Alder, any other questions?

MR. ALDER: No, no other questions. Thank you.

CHAIRMAN JOHNSON: Does the Board have questions?

Mr. Harouny.

MR. HAROUNY: Yes. It has to do with some of the answers that were given.

Would you please describe how you would go about reinjecting the gas and converting the Well No. 2 into an injection. And would it be possible to change course? For the benefit of the Board, if you would explain if it would be possible to change course and reconvert that well back to oil, should you decide that your testing does not justify or is not a good candidate for a miscible gas well.

MR. ZADICK: In the model, what we assumed was that the gas would be injected into the very upper portion of the Navajo completion. So there would be some squeeze of perforations necessary. I'm assuming we might want to change out the tubing string. We'd definitely have to look at a different well head system. We would have to -- in order to do gas injection, we would have to provide for compression and something to control the dew point on the compressed gas. So all of those things take time and money.

As to the second part of your question, if we got to the point where we decided to abandon the reinjection program into the 24-4, and we turn the well around and started producing it, it would, very early on, produce sub economic rates in terms of oil production; because, you recall, the gas doesn't have much monetary value. So it would just be just a function of how patient we were to see whether or not we could reestablish oil production.

Let me go back to one curve and explain what I'm trying to explain to you. Go to the gas liquid permeability.

MR. GILL: What's the exhibit number?

MR. MACDONALD: This one is, I believe it's M-2, "M" as in "Mary" 2.

MR. ZADICK: Gas injection in terms of -- excuse me, I didn't mean to be that close.

Gas injection in terms of oil recovery does not come without paying a price. As you inject gas, the oil permeability drops down to a value of zero at about 3 percent gas saturation. Then if you wanted to turn the process around and start producing the well, you would initially start out with a trapped gas saturation of about 3 percent. And that would hurt the recovery of oil permeability in the system. These things don't -- you don't go up and down this curve without paying a price. There's a hysteresis effect incorporated into it.

The other thing is, is that liquid saturation to gas displacement is trapped at about 45 percent. So when you turn this thing around and try to reestablish oil production for those portions of the reservoir that have been displaced by gas, you're going to leave behind an extremely high liquid saturation. In our model, it's only 10 percent oil and the rest of it's water. But who's to say whether or not those assumptions are correct? So it's not totally a reversible process. It will come with a price.

MR. HAROUNY: Were these two wells drilled at exactly the same time?

MR. ZADICK: No, they were not.

MR. HAROUNY: So you are encouraged enough by -- that 24-1 was drilled first?

MR. ZADICK: Yes, it was.

MR. HAROUNY: So you are encouraged enough that you went -- based on the results of 24-1 -- for a confirmation well, which is basically your 24-4, correct?

MR. ZADICK: Correct. Well, I mean, at the time that we were looking at drilling 24-4, we were hoping that we would have Navajo 2 present at that location. We were also in the process of doing a lot of this test work, like the lab analysis work, et cetera, et cetera. We had -- at the point in time where we initially started modeling the reservoir, we hadn't even completed the well test analysis on 24-1 yet.

Bottom line is, we were really scratching our heads after we started some of the initial work and started seeing what we were dealing with. You know, the combination of low permeability; the extremely volatile nature of this oil; the fact that the reservoir, in terms of lateral extent, appears to be relatively small; and not a lot of oil-in-place in terms of the 10 million barrels that was quoted. So all of those things came as somewhat of a disappointment.

MR. HAROUNY: The other question that I have for you is: How much -- during the initial test period of both 24-1 and 24-4, did you have the well on choke, or was it open flow, or how was it -- how was it flowing?

MR. ZADICK: We were flowing the well into a test separator, and the flowing conditions were minimal. So in other words, there wasn't hardly any choke at all in the well; it was flowing at about 100 PSI in the testing.

MR. HAROUNY: And what was the gas rate from both wells at that time?

MR. ZADICK: Well, I would defer to the exhibit that Emily talked about, where she was quoting the gas-oil ratio for Navajo 1 and Navajo 2. But what we saw during the test was that the gas-oil ratio was continually increasing.

MR. HAROUNY: Gas rate, not ratio.

MR. ZADICK: The gas ratio was increasing. I can't speak as to gas rate. I'd have to go back and look at the data.

MR. HAROUNY: How much are you planning on flaring, then?

MR. ZADICK: I think those numbers were all provided to the Division in terms of -- Ed is going to be addressing that.

CHAIRMAN JOHNSON: Any other questions from the Board?

MR. GILL: Just a couple. Let everybody else ask theirs first.

CHAIRMAN JOHNSON: I believe you're it.

MR. GILL: Okay. You've used some -- sir, you've used some exhibits that are a little new to me. And so I'd like to ask you to go to your exhibits and -- Mr. MacDonald and Mr. Doucet, you can get in on this -- but I'm trying to figure out, in terms of complying with the statute, what that exhibit does to comply with what the statute is asking, so that we have a prima facie minimum case and what it does.

And since some of these exhibits and how you put them together -- to a non scientist -- are a little new, I could use your help.

So let me start with Exhibit J, if I could. In Exhibit J --

MR. MACDONALD: Exhibit J was -- excuse me, Mr. --

MR. GILL: Exhibit J, page 1. And this would be the --

MR. MACDONALD: -- this is the gas analysis?

MR. GILL: Yeah. That's the Fesco gas analysis. So you basically got 1000 BTU gas, quite a diverse mix of inerts, but you're looking at marketable gas that you're going to try and -- that you are requesting be vented or flared. Is that what you're --

MR. ZADICK: No. This is the gas for Navajo 2. The study was on Navajo 1. Ed can address some of these things. But the bottom line is that, even this gas isn't marketable. It has too much nitrogen and CO2 in it. You would still have to reduce the amount of nitrogen and CO2 in this gas to make it pipeline quality.

MR. GILL: I know that's expensive.

MR. ZADICK: Exactly.

MR. GILL: So just factored in the Request for Relief --

MR. ZADICK: Now if you back up one slide here. Now, I didn't present these exhibits.

MR. GILL: Maybe I'm missing something --

MR. ZADICK: I'm trying to clarify them for you.

MR. GILL: I was looking at your Request for Relief. You say -- if you read it, it says, as operator of 24-1 and 24-4, you are requesting the authority to vent gas -- vent or flare gas.

MR. ZADICK: From Navajo 1.

MR. GILL: Okay.

MR. MACDONALD: Both. It would be both -- it would be both wells, but I think --

MR. GILL: Both wells.

MR. MACDONALD: Both wells. But the testimony, and Mr. Higuera is going to address this --

MR. GILL: So we still have one more witness?

MR. MACDONALD: Right. But the idea is, as I think you'll understand -- if I'm putting it in layman's terms -- is that the Navajo 2 has limited potential. I think Emily attested to that, and you will hear with that, that there's limited potential. If this is going to be economic and it's going to be produced, the Navajo 1 is really the targeted production zone that is going to make it economic.

And so you still have to -- you would still have to flare both wells in order to get the testing and the productivity. So that's why it's being requested that way. But I think Tom's testimony -- well, but you would produce for the Navajo 2. This is what Ed is going to get into.

But the idea is, is that the Navajo 2 has limited potential. The most potential, if it's going work, will be the Navajo 1. And again, Mr. Higuera, who's going to testify, will help clarify some of that for you, as far as that potential and the economic.

The other factor I was going to mention at the end of Tom's testimony was: You've heard part of the scenario. You've got to keep in mind in all of this situation, even though these -- phase testing and all of that, there's an economic factor that plays into this hugely. And that's the part that hasn't been presented yet.

MR. GILL: Okay. And that part I've seen before in other hearings with other companies.

But the -- let's go to -- let's go to the second page of J. Am I correct that the -- if you assume 1000 BTU is pipeline quality gas, this is 300 BTU gas is what we're saying there? Will it even ignite?

MR. ZADICK: No. Ed's going to address all of that.

MR. GILL: So you couldn't flare it if you wanted to?

MR. HIGUERA: I will address that.

MR. GILL: Highly unlikely, or you'd have to add something to it?

MR. HIGUERA: I can address it now, or I can address it in the course of my testimony.

CHAIRMAN JOHNSON: He's going to address it in his testimony.

MR. GILL: Oh, I beg your pardon. Okay.

Then let's go to -- again, it's M-1, M-2, and M-3. Let's start with M-1.

For the purposes of the statutory requirements, what is that exhibit satisfying?

MR. MACDONALD: Well, I'll try to answer as best I can, and then I'm going to defer to Mr. Zadick.

What we're trying to define for you, Mr. Gill, by these exhibits, is the reservoir characteristics and what the status is of what we're seeing right now. And part of this is to demonstrate the oil characteristics and how this reservoir will go, and why the -- what they have to do with the flaring of any of the gas versus injection. And Mr. Zadick's testimony, I think, with all these exhibits, is trying to define that you have a highly volatile reservoir, that they need more testing. You cannot do the testing and production required to define and refine that model without allowing the flaring or venting when you take into account what the gas content is, what its characteristics are, what the economics are going to be in this.

So this is setting up, trying to explain to you the reservoir characteristics and the uncertainties and the volatility of this reservoir. And all of these exhibits, that Tom testified to, are intended to help you understand how, and the extensive amount of study that

Wolverine has done here to try and define, and to come up with a way to make this economic, and to address the statutory requirements to prevent waste and to put the gas to beneficial use if it can be done in an economic fashion. And part of the problem, right now, is that more data -- the wells have to be produced to get more data. They've reached the limitations under the regulations. So they have to come before the Board to ask for additional opportunity to flare and vent.

MR. GILL: Would you readdress volatility? What do you mean by "volatility" in layman's terms? I know you've got the pressure in place, is basically X, and you've got a very -- it comes out a solution, 150 pounds difference from that. But what do you mean by "volatility"?

MR. ZADICK: Okay. Go to the PVT slide. This is the first one.

MR. MACDONALD: This is P-1.

MR. ZADICK: No, no, no. Not P-1. PVT slide. Next one back.

MR. MACDONALD: This one?

MR. ZADICK: No, no.

MR. MACDONALD: Oh, I'm sorry. Oh, there we are. Okay. This is referring now to Exhibit N, again.

MR. GILL: This is the CoreLab study and the

Fesco study.

MR. ZADICK: Right.

MR. GILL: And it was surprising to me the correlation up to a point. And then something in their algorithm -- but be that as it may, what do you mean by "volatility"?

MR. ZADICK: "Volatility" is related to the amount of gas that's in solution in the oil at reservoir conditions. And so what it means is that once you go below the bubble point and you pop the cap off, the soda pop --

MR. GILL: Below the bubble point?

MR. ZADICK: Once you go below the bubble point, gas is going to evolve. And it's a measure of how much gas will evolve once you do that. Let's give some for instances.

MR. GILL: Let me make sure I understand what you mean by bubble point. You've got gas in solution. You've got this fluid. And in it, it's like root beer with the lid on it. Right? There's a point where you take that lid off and it takes the inside pressure of that above the bubble point and gas starts to come out a solution.

MR. ZADICK: There's a point where you've dropped below the bubble point and the gas is no longer stable in solution. And because it's not stable, you form two phases, a liquid phase and a gas phase. And that's what we refer to as the "bubble point."

MR. GILL: Okay.

MR. ZADICK: Now, for a normal crude oil system, you know, the West Texas fields were 300 to 400 standard cubic feet per barrel -- you know, conventional black oil, West Texas. You know, "God is good." They're doing all kinds of CO_2 flooding on all that stuff.

When we get to Covenant field, which is only 20 miles removed from here, the solution gas-oil ratio is estimated to be about 40 cubic feet per barrel -- 40 cubic feet per barrel.

When we get to Providence, according to the differential liberation data, the gas-oil ratio at the bubble point is measured to be a little over 4000 cubic feet per barrel. That means for every barrel -- for every reservoir barrel that is brought to the surface, if it is allowed to differentially liberate all of the gas that's contained in it, it will generate 4000 cubic feet of gas at standard conditions, okay. That's what we refer to as "extremely volatile." There's a lot of gas in the oil.

Does that answer your question?

MR. GILL: I think so. I always look to Jake to know if I answered my question or not.

Yeah, it was just a definition of terms, and then how we're fitting that into the requirements of the statute. Thank you, Mr. Chairman.

CHAIRMAN JOHNSON: Any other questions from the Board?

Mr. MacDonald, do you have any redirect questions?

MR. MACDONALD: No I don't, Mr. Chairman.

CHAIRMAN JOHNSON: Mr. Zadick, thank you very much.

MR. MACDONALD: As I said, as we proceed through the last witness, the economic factors and some of the questions that have been asked, Mr. Higuera will either address or is the proper witness to address to. So hopefully this will all come together through his testimony -- hopefully giving you the big picture.

CHAIRMAN JOHNSON: Why don't we take about a ten-minute break and try to reconvene at 3 o'clock.

(A break was taken from 2:50 p.m. to 3:04 p.m.)

CHAIRMAN JOHNSON: Mr. MacDonald.

MR. MACDONALD: Thank you, Mr. Chairman. I will now commence my examination of Mr. Higuera now.

EDWARD A. HIGUERA,

having been first duly sworn,

was examined and testified as follows:

DIRECT EXAMINATION

MR. MACDONALD: Mr. Higuera, please state your name and address for the record.

MR. HIGUERA: Ed Higuera, One Riverfront Plaza, 55 Campau Northwest, Grand Rapids, Michigan, 49503.

MR. MACDONALD: And what is your position with the petitioner and its parent company?

MR. HIGUERA: I'm the manager of development, and I'm a petroleum engineer by degree.

MR. MACDONALD: Mr. Higuera, I'm going to show you what have been marked as Exhibits R through V, inclusive. Do you recognize all of these exhibits?

MR. MORITZ: Yes.

MR. MACDONALD: And they were prepared by you. Is that correct?

MR. HIGUERA: Yes.

MR. MACDONALD: Directing your attention now to Exhibit R, which is shown on the PowerPoint behind the Board, would you please outline for the Board what this represents, and -- as kind of a summary of what your testimony will be.

MR. HIGUERA: Certainly. We've heard a lot of information here, both from Emily and from Tom. And I want to give -- we've also heard a lot of your questions.

So as I go through my presentation, I will try to address some of those questions that you've had that I've been writing on my notepad.

But I think it's important for us to kind of look at the take-aways from Emily's presentation, and then the take-aways from Tom, and then let me kind of put those together into some sort of strategy for Wolverine and the economic picture.

The take-away, plain and simply from Emily's presentation, is that we have drilled two wells. And we have tested those wells on a limited basis. And while we wish they were as good as Covenant, they're not. And so as we reported in the original Board filing, we have two wells that are comparable in terms of production -- roughly about 70 barrels a day, whether it's Navajo 1 or Navajo 2.

There are some differences in those characteristics. For example, the Navajo 2 made very little, if any, water. But the Navajo 1, as indicated in that production curve that she showed, made water -- actually started making more water at the tail end of that test. That becomes important because when we talk about the model results, what Tom didn't tell you is how much water we're going to have move with all that production and deal with.

The second thing is, we have in the Navajo 2 a gas that is -- a good significant of it is hydrocarbon. But there are still some large components that are CO2 or nitrogen. These would have to be dealt with if we were going to make this saleable gas.

Most of our focus has been the Navajo 1 reservoir; and unfortunately, that's the one that has 80 percent CO2 and about 6 percent nitrogen. So you're left with about 14 percent, or so, of hydrocarbon.

The other thing I want to remind us of is that we have done a lot of work here, but we are still basing it on a finite dataset. We have two wells. We have a core seismic grid. We had to import core data from Covenant, where it was applicable. And we've had to import core data, or permeability -- relative permeability data from the Nugget reservoirs. So we're putting our best foot forward in the reservoir model. And as Tom emphasized, we pushed it to the optimistic level, because we wanted to see: Is there an opportunity here for us? But we can't forget that the model is predicting rates that are significantly higher than what we have today. And I will go over that a little bit. So my presentation is to go over how we kind of see this unfolding if you give us permission to do this.

The capital costs that we would be facing, kind of the operational strategy with respect to the two wells, and then we also looked at the various options. Can we produce and flare this gas? Can we produce one and inject the other? And what does that mean in terms of our equipment requirement? And is there any possible way to treat this gas and sell it?

Those are the three options that I want to look at. And through my testimony, what I will try to do is address some of the questions that I've heard over the last 3 1/2 hours.

MR. MACDONALD: Starting with Exhibit R then, again. Would you please explain to the Board what this represents.

MR. HIGUERA: Yeah. My task in this entire evaluation was to take the numbers from our model that was developed by Tom Zadick, look at it in terms of its forecast and see what kind of costs it would be to get this accomplished. And so what I'm going to review is the three options that we looked at. There are more options out there, but they're not really realistic at this time, okay, because the volumes are so small or because there's treatment requirements for the gas, or there's not infrastructure in there for electricity, for example.

So while I look at three options, which are:

Flaring the gas and producing the two existing wells; converting one to a gas injection; or producing one well -- or producing both wells and treating it, it's not to say that we haven't looked at, for example, taking this gas and burning it and generating some sort of electricity and seeing if there's some value to that. We have.

But the overlying theme here that I want you to remember from my presentation is: I have to deal with the reality. And the reality that I have is, I have two wells that make about 68 to 70 barrels a day. That's what I get to work with. Now, Tom's model suggests it could be better; and we certainly will spend the money to see if that's a true statement. We have within our plan, our strategy, to rework those wells, conduct additional testing.

So as I walk through my slides, I'm just going to talk through Options 1, 2, and 3, kind of the money and the economics of accomplishing this, and then address any of your questions, okay?

MR. MACDONALD: All right. I'm going to now direct your attention to Exhibit S, your first substantive slide, and ask you to explain this exhibit to the Board.

MR. HIGUERA: Okay. This curve probably best illustrates the end results of Tom's model. And so what you have is, I took the two-well model forecast that Tom put together, and I plotted the oil, gas, and water on this curve. So you see that the model is predicting a peak production of about 400 barrels a day with both wells running -- and again, Navajo 1. And again, I compare that to a Navajo 1 well today, that's making about 68 barrels a day.

You'll also see the gas rates up there at approximately 2.1 million. So there was an earlier question about what is the volume of gas that you are going to flare. Our model, and our expectation of the model, is correct. It would be approximately 2.1 million a day. Now, I remind you that the current production is probably closer to 400 mcf a day with one well, or about 800 with two wells.

So for us to achieve these types of results, please bear in mind that we have to have a production that basically triples on each of these wells and stays at that rate for an entire year to follow his model. So I don't want us to put too much credence yet into the model, because I think it's premature. But this is the curve that I worked with in terms of my economics. I looked at what's the best case scenario. And this is what the model generated.

You'll see that the production increases after the first year. That is really just a reflection of the timing, more than anything. It's a reflection that the two wells were drilled at different times. And it was just really trying to put the appropriate revenue stream with the appropriate investment.

MR. GILL: Just one question: Were these numbers normalized in other fields at all, or is this just the two wells?

MR. HIGUERA: This is the two wells with the reservoir model, as Tom indicated, with all those assumptions that go with it.

MR. GILL: Thank you.

MR. HIGUERA: Okay. So if I had to -- if I was putting it together without the model, I would be looking at 140 barrels a day, and trying to work with that, and making some assumptions about increasing that production.

So that's the curve that we used for our economic evaluation.

MR. MACDONALD: Moving on to Exhibit T. Please explain to the Board what this represents.

MR. HIGUERA: Okay. This exhibit is a summary of what would be required to produce these two wells, and the amount of costs that we have invested in these wells, the amount of costs that we would have to invest in these wells to produce them.

So as part of our assessment of this, we've contracted a facilities engineer or company, and they have provided us estimates, and they have provided us some advice, and so that is incorporated in some of these numbers that I have.

So when you look at producing two wells, we see this as requiring conventional oil field equipment: In-line heater; high pressure separator; and then a low pressure separator; and then storage, crude oil storage, water storage; and then, of course, the flare knock-out, and flare unit.

There was a question, Can this Navajo 1 gas burn? What we see happening is this: On the initial days, we have a well that's completed in Navajo 2, which has methane in it; and we see the Navajo 1. We would like to produce the Navajo 2 formation while it's completed in that, before we recomplete into Navajo 1.

So on the early days, we would see a Navajo 1 and a Navajo 2 producer -- the Navajo 2 providing us the pilot gas that we need and the hydrocarbon that would supplement this. However, we've also looked at a Navajo 1-only scenario. And it is the opinion of our facilities engineering firm and the vendors that this Navajo 1 stream will burn. And we have had it burn. I mean, during our testing, it burned.

So if you look at the Navajo 1 BTU content, it's about 300. The federal regs require, I think, a minimum of 200, under 40 CFR 60, which is a performance standard for new sources. So we satisfy that.

During shutdown periods or startups period, we would either have the Navajo 2 gas as our supplement pilot gas; and when we go to Navajo 1 only, we would have on-site propane, which would operate the pilots during startup.

This just adds another complexity and another expense. So I hope you appreciate that this is really not a simple thing to do, with this 80 percent plus inert gas. But carrying on to my first bullet there, then, our engineers estimate for that type of equipment, it's about $1.4 million to equip these two wells.

The other thing that we're going to have to do is expend time and money to rework both these wells. As Tom indicated, the 24-4 well had some damage, and there's additional interval that should be completed. So we will spend money on that to improve those rates. We'll eventually have to spend more money on the Arapien Valley 24-1 to recomplete it from the Navajo 2 into a Navajo 1 producer. So our estimates include monies for that.

Now, we have already spent a considerable amount of money. It's some cost for us, but it's a real dollar value to us and to our partners. So we have included that in our economic evaluation. And for simplicity's sake, in terms of scoping economics, I've assumed a fixed oil price at $70. That's realized at the well. At the time I did this earlier, that was about $80 oil or 82, that's about where it was when I first did this. Today, it's about 78, so this is really too high. But we'll run with it, okay.

Our operating costs, I assumed, were $9500 per month per well, plus water disposal. At our Covenant field, our operating costs are about $18,000 per month per well. That includes all the infrastructure for the wells, all the electricity, all the chemical treatment, disposal, and staff. I assumed that my costs are going to be lower at these wells. But because of the flow stream, the CO2, I know I'm going to be spending quite a bit of money on chemicals for corrosion inhibitor. So the 9500 is rolled into our estimate. And also under this scenario, there is no gas stream. So there is no gas revenue. And for this combined economic -- scoping economics for this scenario, you get a discounted cash flow of about $767,000. And you get an internal rate of return of about 10 percent.

Now, this is the optimistic case from the model.

We would certainly not achieve this if we can't get more than 60 or 70 barrels a day per well, or if our costs were high.

Now as I indicated in my opening comments, Tom didn't really mention water, but we're going to move a lot of water, as you can see from the previous graph. So these wells are going to make hundreds of barrels a day of water. We're going to have to deal with that. One of our concerns on this initial point is, looking at the 24-4 curve at the last few days of production. Unfortunately, that was the last we could produce, so we're not sure if those steep increase in water is a true reflection of a reservoir condition changing, or just an unloading of the tubing, for example, on that day. But it is a concern to us, and it will be a real expense to us. So even on the front end, as we talk about what kind of testing and phases, we're going to have to haul the water off. So some of our cost scenarios incorporate transportation and disposal of water.

We don't have an alternative at this time. We don't have a disposal zone. We don't have a disposal well. So part of our strategy is to monitor that water, see what our real costs for all of these activities are, and then evaluate. The other option that we looked at is what Tom had modeled -- one producer, one injector.

MR. MACDONALD: First of all, before going to that. Also --

MR. GILL: What exhibit?

MR. MACDONALD: Okay. Right now we are on -- this is Exhibit T, the Option 1.

MR. GILL: Before you leave that exhibit, would you comment on the third bullet? Just tell us what that means.

MR. HIGUERA: All right, I will certainly do that. We've drilled two wells out there. These were not just Navajo wells. They were deep exploration wells. The drilling out here can be complex and it can be expensive. So the 32 incorporates the drilling costs, the completion costs, the permitting costs, all of that, that gets a well done -- location work. That's what you have. And there's some infrastructure costs in there, because of these engineers in here do work for you. So that's what that is.

You had mentioned earlier about salt flow. It's one of our issues. So in terms of costs for our wells, we design for plastic salts, say, at depth. So our casing program is much more expensive than a traditional well down to 9000 feet.

We have small amounts of H_2S, but we have CO_2. So our tree and our casing are designed to accommodate that, or deal with that. So -- but that cost is real costs, some costs that we have incurred in this wildcat drilling and testing phase.

MR. HAROUNY: Just for the two wells?

MR. HIGUERA: Just for the two wells.

MR. HAROUNY: It includes cost of lease acquisition and everything else?

MR. HIGUERA: It does not include seismic or land. It just includes permitting two wells, building those locations, drilling them, setting casing, completing them, some equipment -- rental equipment, all that goes with that, you know, power generators -- because there's no infrastructure out there. It's expensive.

Now one of the things you have to remember, for example, the 24-4 was drilled to evaluate Navajo 1. It was drilled to evaluate the presence of Navajo 2 and whether or not it's productive at that location. And we were also looking at some deeper horizons. So that number incorporates more than just Navajo activity, but it does incorporate all the activity for that well.

MR. MACDONALD: And also, I just want you to point out and confirm that this is the option that, essentially, Wolverine is asking the Board for at this point. This is the one that you are committed to go forward, assuming the authorization is given. Is that correct?

MR. HIGUERA: That is correct. I will touch on some of our, kind of, go-forward strategy at the end, but that is a correct statement. This is what we are recommending.

MR. HAROUNY: Your rate of return was established based on what -- the production from two wells? Is that the .97 million barrels that we saw before?

MR. HIGUERA: The economic evaluation is based on the two wells modeled at the rates that Tom has modeled them, and as shown in that curve.

MR. MACDONALD: It's shown on Exhibit S.

MR. HIGUERA: Exhibit S.

MR. MACDONALD: That's the basis for it.

MR. HAROUNY: So no additional wells. Nothing --

MR. HIGUERA: -- no additional wells.

MR. HAROUNY: So the two wells will give you 10 percent, right now, if you completed them.

MR. HIGUERA: If you believe all things. Now, that's if you believe all things, right? The model turns out to be correct, and your water production doesn't go up too fast, et cetera. To me, this is the optimistic case for us. This has enough interest for us to evaluate it and spend more money. Okay.

MR. MACDONALD: All right. Now directing your attention to what has been marked as Exhibit U, would you please explain to the Board what this represents.

MR. HIGUERA: Option 2 is where we look at keeping one producer, which is the Arapien Valley 24-1, and converting -- eventually converting the 24-4 to a gas-injection well. So again, require all the traditional, conventional, on-field handling equipment, which is that $1.4 million estimate, then it's going to require additional capital for gas compression and dehydration. Still have to rework the wells. And then you will subsequently lose the revenue from the one well.

So this economic evaluation, then, contemplates basically a one-producer, one-injector well scenario. And it's -- used the same basic cost structure. I really didn't deviate the cost significantly, even though you will have additional costs because of compression. But it was already negative, significantly negative, that I didn't feel it warranted. But that being said, at a 10 percent discounted cash flow, you get about a 7.8 percent rate of return, and it's about a negative $3.9 million.

MR. JENSEN: How much again?

MR. HIGUERA: 3.9 million negative. And that's primarily because you take a hit in those earlier years on that production.

MR. HAROUNY: What is the cost of drilling a well straight forward down to Navajo 1 or Navajo 2, and no deeper, nothing else except completion.

MR. HIGUERA: If everything goes right?

MR. HAROUNY: Yeah. And your casing program being just designed for that purpose.

MR. HIGUERA: Yeah. If everything goes right, you can probably drill it for about $3 1/2 million to TD, then add casing and completion. So you are somewhere around 5- to $6 million, if everything goes right.

Understand -- let me give you an appreciation for costs here. When you drill into the top of the Navajo, in many areas it's very tight and very hard. You can take a Type 6 drilling bit and pretty much wear it out in 50 feet. You can't drill it with a PDC; because we tried, and it will ruin it.

So the drilling costs that we incur here are quite expensive relative to a lot of different areas we've been involved with. So when I say it's 6- and 7 1/2, please, because we've drilled them all from about a 3 1/2 million all the way up to these. And sometimes we've dealt with plastic salts, we've dealt with deformed casing from the plastic salts, and we've had to address those in terms of our design and our approach. And so for those have been around long enough to drill in the Overthrust belt of Wyoming, same kind of problem, but different -- we have it in the Arapien section, they had it in the Preuss salt, and there are other examples of that, too.

So this Option 2 is the option that was also modeled by Tom.

Option 3 kind of says, Well what -- there is some gas here.

MR. MACDONALD: Hang on. You are jumping ahead of me here.

Now we're going to go to what's been marked as Exhibit V, which is a two-page exhibit. Page V-1 is shown first. Now go ahead and address it.

MR. HIGUERA: Okay. I don't mean to go too fast. So if I am, just slow me down. I just try to be efficient.

Option 3 looks at the scenario: What would it cost to treat this gas, okay. And what you have here, again, first bullet, conventional equipment, 1.4 million. Where you really start to have a significant cost increase is handling this gas and actually removing the CO_2. Because the CO_2 influences heavily the type of equipment that you can use. So our estimate, and our engineer's estimate, is about $8.2 million to remove the CO2. You're not even really removing all of the nitrogen at this point. So this just kind of looks at, Well, what would it take to do a gas plant? This gas plant was based on a 3-million-a-day type plant. You can scale it down, but you are probably not going to save that much if you scale it down to 2 or 2 1/2 million a day. It requires the construction of about a 4 1/2 -- 4.6 mile pipeline and metering station --

MR. MACDONALD: Let me stop you there. I'm going to switch over to V-2.

MR. HIGUERA: V-2 shows you -- we showed you the -- very, very early on in this presentation -- kind of the aerial view of the two wells and the mountain ranges. This shows you the two locations, shows you a possible route for the pipeline. It would come back over into Axtell and Highway 89, where there is an existing Questar pipeline.

You're constructing the gas through some pretty narrow road areas. It's not simple cornfield-type construction. But you required that. So when you add it all up, this is a $42 million option, including your existing wells, including your equipment, including gas treatment plant, et cetera. This gets you about a 4.2

million negative, at present value discounted 10 percent.

MR. MACDONALD: I'd like to address one issue. Since this is the one option that would account for both oil and gas revenue stream -- you've only got the assumption of oil price down here --

MR. HIGUERA: Yes.

MR. MACDONALD: -- but you did account for a gas price, as well, in the gas revenue. Is that correct?

MR. HIGUERA: That is correct. What I did is, I took the gas stream modeled off of Tom's model, and which is displayed in that previous curve; I subtracted all the inert gases off of it, so we could just have the straight hydrocarbon. And so there is a gas stream associated with this option. I assumed $5 gas. Why not, right -- fixed. It's not going to help, and I don't think there's a lot of people who get $5 gas out here, or for that matter, $70 fixed. But I wanted to look at it, right. This is a scoping economics. Can it even be achieved? And based on the engineers' estimates for equipment costs, I don't think so. So in my mind, this option is not really an option for us. It's two capital intensive on two wells that have limited data.

And so as we look through our options and kind of our go-forward strategy, what we would like from the Board and from the State and the BLM is the ability to produce both wells, the ability to flare the produced gas and to construct our facility out there. And that's our desire. And so when you look at the model -- the model says about 2, 2.1 -- we would be happy with something like a 2-million-a-day. And if for reason we are very successful in our recompletions and stimulations and we get more oil and more gas, we can address that. But that's kind of where we're going.

And so our go-forward strategy, in addition to coming to this Board and getting this approval, is to -- and we've started this already -- is do our permit analysis. So we retained a firm locally, here, to do an air permit assessment for us. We know we're going to have to address our environmental assessment under NEPA and revisit that, since we haven't since the original drilling of those wells. We know we're going to have to address some BLM concerns. But after all of those kind of things and if we get Board approval, then we know we're going to do some design work on this facility, purchase some equipment, purchase the flare, undertake the recompletions and the stimulations, and then start testing. So we may not do a lot of work on the Navajo 2. We'd just like to produce that, actually, and flare it for a while and see what happens while we work through some of these other things. But that's kind of the scenario that we see.

So even as we get past this portion of the strategy, the Board approval -- if we can get that -- then we see, you know, kind of a longer term commitment to this field in terms of the permit analysis, and the NEPA, and the design of the equipment, and then putting the wells on test. So this is going to take many months to kind of undertake and get all this.

My personal view on testing: I've got two wells that make about 70 barrels a day, and I've got to stimulate them and then test them again, before we get too excited. We may do that in phases. You know, do the one, see how it works.

So personally, I like Tom's estimate of three years. I think short-term testing is not going to tell us what we need, because the investment dollars to get to that next phase are significant, and the investment dollars that we have in place, although some, certainly are in the back of some of our partners' minds. And so we need to be cognizant of that.

That's kind of where I would like to go. And as part of this, we will address the design basis, we'll address the health and safety issues, and we'll build a facility that can be operated well and safely and within the confines of any permit requirements. And for those of you that had the opportunity ever to drive through Sigurd, you've seen work there, our facility there, and we build nice facilities. And we'd do the same thing here. That's kind of where Wolverine, on the production side, would like to be. And that's it.

MR. JENSEN: May I ask a question on Option No. 3.

MR. HIGUERA: Yes, sir.

MR. JENSEN: Did you look at, is there any potential for a revenue stream on the CO2 that you've captured.

MR. HIGUERA: We're not -- first of all, we're not aware of any needs for CO2 immediately in the area. So we haven't looked at it in terms of any commercial use, in terms of compressing it and somehow selling it as a CO2 source. My gut tells me there's really not a lot of value in that, only because the volume really is not that significant. When you compare it to other CO2 fields in the state of Utah or Wyoming, they have significantly larger volumes available to them.

The second thing is, even if you wanted to contemplate that scenario, you would have to have some level of confidence in the flow stream or in the forecast. So you'd have to have some production testing period, let's say 24 months. And then you would say, Okay, there is a revenue stream as CO_2. Then you'd have to make the additional investments into that equipment, to actually separate it and polish it. And quite honestly, I'm not sure what the requirements are for polishing CO_2 off of an oil field to make it available at food grade level. I think there are other alternatives for those types of customers.

MR. JENSEN: So the answer to my question is no?

MR. HIGUERA: To the extent that I have a formal model, no. To the extent that we've pondered it and contemplated it, yes.

MR. JENSEN: I guess my question is: It's not reflected in Option 3?

MR. HIGUERA: It is not reflected. There is no revenue stream for CO_2 reflected in Option 3. In fact, Option 3, the CO_2 would be vented. So from a venting comparison of CO_2 going up the stack, Option 3 assumes that you remove all your inerts and it goes off into the atmosphere. So in that respect, it's similar to Option 1.

Now, one of the things that I'd like to say, you know, we hear about 2.1 million and it sounds like a lot, a big value -- and it is. I wish it was all hydrocarbon. But it's primarily CO_2. So when you look at these types of volumes -- just to put this into context for us -- if we had both wells producing out of the Navajo 1 at the rates that the model predict, which is about 2 million a day, roughly, your C02 would be about 684 metric tons a year. It sounds like a lot. If you look at some of the refineries you have in Salt Lake City -- the Holly, or whatever, not the largest one -- they're probably in the neighborhood of 20,000 to 50,000 metric tons per year.

So in our mind, this is a relatively small volume to flare. And all of that will be addressed under an air permit evaluation. But I'll address any other questions that you might have.

MR. MACDONALD: Before we do that, let me add a couple more questions on it. One of the other issues that has been touched upon, in a very small amount, is the hydrogen sulfide. And I just wanted to confirm that you were required to provide -- both to the BLM and the State -- a hydrogen sulfide plan as part of the drilling of these wells. Is that correct?

MR. HIGUERA: Yeah. As part of drilling we have an H2S contingency plan, or operations plan. In terms of our own production operations, we cover everything from respiratory --

(the reporter interrupted for clarification.)

MR. HIGUERA: Let me rephrase that. As part of our production operations, we cover the whole gamut of health and safety, including respiratory protection, confined space entry, et cetera. So as we go forward, in addition to the H2S contingency plan, which is primarily geared towards drilling, we would incorporate that whole safety program that we have now in our operations for this facility, as well.

MR. MACDONALD: All right. One last thing I'd like to point out to the Board, the exhibits that Mr. Higuera prepared and submitted, in my mind, addressed the remaining regulatory criteria under the regulation under 649-3-20 sections 5.4 through 5.7. So again, that is the additional regulatory criteria as part of this petition. His testimony and exhibits address those criteria, as well.

And that would conclude my examination of Mr. Higuera.

CHAIRMAN JOHNSON: Mr. Alder, does the State have questions for Mr. Higuera?

MR. ALDER: I believe we do. Just one question from Mr. Doucet.

CROSS-EXAMINATION

BY MR. DOUCET:

MR. DOUCET: I've just got one question. You had mentioned, on the Navajo 2 production you would continue to produce that. How long do you expect production to go on for that well, and how much flaring from that well do you expect?

MR. HIGUERA: As Tom indicated in his presentation, and as Emily indicated, the Navajo 2 has oil-in-place of about a half a million. It's extremely tight. We're talking tenths of millidarcies. And when you look at the curve in that production period -- we have looked at that curve, we have normalized the production, and we have looked at it. Now, what will happen on Day 90 or Day 100, we don't know. But as part of our original filing to the Board, I think we estimated there's probably about 32,000 barrels of hydrocarbon that we can recover. And that's what we would do. I see that well producing for a couple years, or so, and not much more. But we would do it until it's uneconomical, then we would move up into the Navajo 1.

MR. DOUCET: Okay. Thanks.

CHAIRMAN JOHNSON: Is that all, Mr. Alder?

CROSS-EXAMINATION

BY MR. ALDER:

MR. ALDER: I was just wondering if you gave any consideration to the amount of gas that might be used in the operations.

MR. HIGUERA: Yeah. In the original filing, we estimated really a small amount, like 10 mcf a day.

There's not a lot of -- when you look at your equipment and that we're going to have on-site, what you will burn gas in primarily is an in-line heater. The fluid is going to come up at a warm enough temperature that once you get past that hydrate formation temperature, once you get low enough pressure to do that -- and we've experienced this in testing these wells -- you don't really need to burn gas to heat these units.

So once all of that is taken care of, I would expect very little, if any, of the gas is used in the equipment itself. And as I mentioned before, probably as part of an operational strategy in terms of safety and everything else, we would have a propane, on-site pilot type thing that would be connected and configured to burn when the flare is going off or on. So I would expect little, if any, natural gas to be used in our operations --

MR. ALDER: Thank you. That's all.

MR. HIGUERA: -- produce gas.

CHAIRMAN JOHNSON: Does the Board have questions for Mr. Higuera?

MR. GILL: I have a couple, but I always like to go after Jake.

MR. HAROUNY: Okay, I'll go.

Mr. Higuera, now you mentioned that you've drilled these two wells as a wildcat for deeper -- other horizons.

MR. HIGUERA: Yep.

MR. HAROUNY: They were not related to each other, so to speak. They were part of -- not for the drilling of this particular reservoir.

MR. HIGUERA: They were deeper horizons, below the Navajo 1.

MR. HAROUNY: And also your testimony is that currently, if you were given permission to vent the gas, that you would get a -- $40 million -- roughly $40 million by the time you're done, sunk into this, that you'd get a 10 percent rate of return from these two wells only.

MR. HIGUERA: Under Option 1, we would have close to 32 million, not the 42.

MR. HAROUNY: Thirty-two million.

MR. HIGUERA: Yeah, and you get some marginal rate of return.

MR. HAROUNY: So two wells, at an average cost of 16 million plus, $16 million per well, give you 10 percent rate of return, correct?

MR. HIGUERA: Yes.

MR. HAROUNY: Based on what you've seen so far from the Navajo 1, aren't you encouraged enough to drill additional wells? Because your well costs are not $16 million anymore. You're looking at maybe -- with more, you know, knowledge of the field, you're going to be drilling these, at maybe, four to five, or maybe even less.

MR. HIGUERA: Well, let me address that. When you say, Haven't you seen enough to be encouraged? We saw enough to drill the second well. We also had deeper horizons that we wanted to evaluate. We also wanted to know if the Navajo 2 was present laterally, because we had some questions about that portion of the field.

So today, the Navajo 1 is a 68-barrel-a-day well. It is not 180-barrel-a-day well. So my encouragement is -- I can't be too encouraged yet, unless I can get that rate higher and demonstrate that the model actually has some validity to it. So I would not be recommending to our partners to drill another well for 68 barrels a day, at these costs.

MR. HAROUNY: But the overall recovery, the testimony that was presented to us, that's not the rate that was the issue, it's the overall million barrels, or .97 --

MR. HIGUERA: But understand --

MR. HAROUNY: -- barrels of oil.

MR. HIGUERA: -- that is a model that is based on importing Covenant relative permeability curves, importing relative permeability curves from the Nugget formation. It is not for this reservoir. We have not conducted a whole core of this reservoir. So remember that Tom was asked to look at this as favorably as he could, to see if this would work for us. It is certainly not, in my opinion, with the data that we had, which is no more than two data points and two well tests that go about two months each, it is not enough to make a recommendation to drill more wells. And even in our own modeling, if we want to go the modeling, and say, okay, the modeling has some validity, a third well is not adding that much incremental reserves to where you'd drill for it.

MR. HAROUNY: The issue is that -- the testimony -- your prior testimony was that the oil-in-place calculated for Navajo 1 is estimated roughly at a little over 10 million barrels.

MR. HIGUERA: Yes.

MR. HAROUNY: Then is it your testimony that you are only going to recover 10 percent of the oil-in-place by producing these two wells?

MR. HIGUERA: It is my testimony that the reservoir model projects an EUR of roughly 900,000 at ten years. If you extrapolate that out to 25 years, it might get up to 1.6 or 1.7 million, so roughly 17 percent. That's not all that unusual for a solution gas drive. However, this is a solution gas drive that comes with a heavy cost structure to it, to produce it. And in the model -- understand the model is roughly three times what we're producing now, and it must stay at that level for an entire year. We haven't seen that, so I can't get encouraged, yet.

What I see as a model as, as we took the best information, we went the extra mile and asked Tom to look at a reservoir model, as opposed to me slapping down a triangle and doing a curve and saying, You are making 68 barrels a day; it's going to be at 45 barrels a day in another six months.

MR. HAROUNY: I'm kind of conflicted -- sorry -- here.

MR. HIGUERA: Well, I'm conflicted, too, because what I sense is that you want to believe the model, and I want to believe it, too. But that model is based on certain assumptions and limited data. We can't hang our hat on that and make a tremendous investment based on a model without that additional testing.

MR. HAROUNY: That conflicted part that I -- the difference for me is in numbers. The numbers that we were given before lunch for oil-gas ratio were the actual production numbers, correct?

MR. HIGUERA: The numbers that were provided in the original Board filing, and which were discussed by Emily, were the producing oil, water, gas rates and a producing GOR at the end of the test.

MR. HAROUNY: And then that was corrected to the model --

MR. HIGUERA: No.

MR. HAROUNY: -- numbers.

MR. HIGUERA: No. The producing GOR is not the appropriate GOR to use when calculating original gas-in-place. The correct number to use is a PVT derived solution gas oil-in-place. What the PVT did here is, because this oil is so volatile, it's -- the final oil volume, B sub-o, is a function of how you produce it and the pressure drops it goes through. So in a oil like this, the types of pressure you see in the various Stage 1 or Stage 2 flash differential equations, will dictate what kind of recovery you have in stock tank barrels, okay.

So getting back to Gill -- Gill, your comment about volatile oil, think of it this way: You have a volume of oil, and within that oil is cram full of CO2 gas. It's got a volume of 1, let's say. When you bring that to the surface, the gas is liberated, the oil shrinks. It shrinks down to about a third of its volume. Now, depending on how you run that through your high pressure separator to low pressure separator to tanks, that might change it from a third to .28, let's say. So the GOR that Emily used is a PVT derived solution GOR for the reservoir under original conditions as it applied through a production scenario.

To give you a different scenario. For example, in Covenant our field, B sub-o is about -- formation volume factor -- is about 1.07. So every barrel that's in the ground that comes up to the surface, it's about a barrel -- barrel for barrel. So when you do your volumetrics and you calculate X barrels in the ground, you are going to get about X barrels to the surface, depending on what cover you assume.

Here, you are going to calculate a certain volume of oil in the ground, but when it's brought up to the surface, it shrinks, you get a third of it. That's what that formation volume factor is telling you when it's at a 2.8 or a 3.

So when you look at this reservoir and you look at the modeling work that's done, we -- our volumetric estimate, based on two wells, based on seismic integration, is about 10 million. We don't yet know what the recovery, because we don't yet know all the drive mechanisms.

MR. HAROUNY: That brings me to my second question, which is: We've heard prior testimony this was a waterdrive.

MR. HIGUERA: Okay. What you heard is, when we modeled it, we modeled it as such that we have a constant pressure boundary; in other words, that the water aquifer will support this reservoir and be a, quote, waterdrive. We don't know the level of that waterdrive. We don't know if it's a weak waterdrive or a strong waterdrive. We do know that we're making water, and that's a concern. That could be related to a lot of different things.

So we do have some component of aquifer expansion and aquifer drive in the model. To the extent it influences recovery greater than the model, or less than the model, or at the model, I can't comment. I don't have that data, today. We just don't know yet.

MR. HAROUNY: For economics purposes, would it be best for us to just look at the cost of the drilling -- the drilling a well and completing a well to this level and not all the extra activities that you, you know, chose to take on for the extra costs, the economics of the well from this level versus the benefits of what we are trying to do? Isn't that a way to look at it?

MR. HIGUERA: It is a way to look at it. I don't think it's the best way to look at it. You have to understand that we have invested a lot of money. It is sunk costs, right? We know that. But that doesn't mean that every partner thinks the same way as Wolverine does. So to the extent that a partner wants to sell his interest, he will expect some sort of compensation for sunk costs.

So I like to look at full cycle for this type of decision. Whether or not you come back in two to three years and say, You know what? These rates are actually pretty good. They're close to the model. Maybe we should reevaluate. I mean, Tom mentioned doing some additional testing and -- reservoir testing. Maybe the testing supports that the reservoir is a little differently than we have it mapped. And so from an incremental economic evaluation on a third well, I would agree with you. At that point, that decision on that third well is going to be based on the reserves for that well and costs for that well, which might be 6 million or 7 or 5.8, or whatever the costs may be.

Did I address all your questions.

MR. PAYNE: Could I follow up?

CHAIRMAN JOHNSON: Go ahead.

MR. PAYNE: Could you comment a bit on what the net present value would be if you excluded those sunk costs. I'm a little uncomfortable if your including those in this economic evaluation.

MR. HIGUERA: Well, our rule --

MR. PAYNE: Let me just clarify a little bit. Our rule requires an economic evaluation to support the wasting of gas, that it be much more expensive to try to conserve the gas. In my view, that would be looking from today forward. I mean, what you are looking at is investor relations. What I'm looking at is the upcoming evaluation of wasting gas from here forward, versus conserving gas.

MR. HIGUERA: Yeah. I can comment on it, but basically we have two different approaches to evaluate this prospect. So to the extent that I drop off all the sunk costs and look at it only today, sure, the net present value should be higher.

MR. PAYNE: Can you tell me if there is a positive net present value in reinjection if you eliminated some costs?

MR. HIGUERA: I don't have that, but I would assume that it would be positive, because you are taking that investment straight off on the year times zero time one, and so it should be. But the economics are also based on a model. So if I'm going to redo the evaluation, do I get to go back and use accurate test results or model results?

MR. PAYNE: I agree with you, definitely. But this is the model you brought forward. So I'm uncomfortable that you continue to say, This is a very optimistic model. If you don't like this model and want to continue to attack it in the way you are, bring us a model that you can count on.

MR. HIGUERA: Let me address that, Kelly -- Mr. Payne -- sorry. I'm not attacking the model. This is a model that Wolverine has had prepared. But you need to understand the context of the model. And the context of the model is two wells. Tom could have just as easily --

MR. PAYNE: That's not lost on me. I don't need you to re-explain to me the weakness of the model.

MR. HIGUERA: But you had characterized me as attacking the model --

MR. PAYNE: Maybe the wrong word was "attacking the model."

MR. HIGUERA: -- and so the model -- let me finish my thought -- the model is presented to assist you and give you the full realm of the possibility, not necessarily be the possibility.

MR. PAYNE: I understand that.

MR. HIGUERA: And so the difficulty I have is, I have to deal with the reality I have today, which is two wells that may do better, and the investment I have to look at, at that point, and all the regulatory scheme -- that's where I'm at.

MR. PAYNE: Okay. Fair enough. I'm looking at our rule that says we're required an evaluation to justify this. You tell me that you want me to look at a realm of possibilities, but you bring me one model and tell me not to hang my hat on it. That's where I'm a little bit concerned.

If you were wanting this -- I mean, I don't understand why you even bring the most optimistic case to this forum. I don't think that it's appropriate to bring the most optimistic case. I think it would have been more appropriate for you to bring a realistic case. But you've chosen to bring the optimistic case. That's what we're going to have to rely on. My question was simply around sunk cost.

My second question is, we require an economic evaluation, and you don't spell out those details. My question, I guess, is more for the Board: This is the first time I've been on a flaring -- heard a flaring case. Is the level of detail provided in this economic -- in their case, sufficient to call it an economic evaluation? We simply have the results of an economic model without the underlying assumptions, without -- I would expect to see a cash flow model -- simplified cash flow model that would show us where these net present values came from. But we don't even have that. I could probably piece together some of it, but not all of it.

You, for instance, show me that my OPEX is $9500 per month, plus something. I don't know what the plus is. If I were to try to verify the model, I can't because I don't know what the plus is. So I'm a little uncomfortable with the level of detail. And I'm not saying that this isn't a good project, this isn't a good thing, but I'm uncomfortable with the level of detail that's been provided for an economic evaluation, which is what this hinges on. The ultimate question here is: Is it uneconomic to conserve gas? I don't know.

Jake, do you have any comments in terms of the level of detail that has been provided to us?

MR. HAROUNY: I share your views completely on the economic evaluation side of it; because whatever sunk costs are, it has a huge determination on the economic. This could be a -- could go from 10 percent to whatever percent rate of return. But that's -- the same costs were done. You're talking that it'd be making 16 million and 5 million.

MR. PAYNE: I agree whole-heartedly. When I'm required to do an economic model in my business, which is natural resource development, I exclude some costs. So I'm a little uncomfortable.

MR. HIGUERA: I appreciate the comment. This is a debate we could have for a long time. But let's look at it today and go forward. How do I validate an economic model? You've got to produce the well. You have to. We're dealing with a 55-day test or a 61-day test, as the case may be. And that's what we have.

MR. PAYNE: I'm not asking you to validate. My question isn't the validity of the numbers. I understand there's going to be uncertainty about that model. My discomfort comes from, I don't even have the inputs to the model to look at, fair enough?

MR. HIGUERA: That's fair.

CHAIRMAN JOHNSON: Mr. Gill.

MR. GILL: My questions go to reservoir characteristics. And whether this is a fair question for you, or a previous witness, or Mr. Doucet, I don't know. But the question is -- is: What's the difference between a retrograde condensate reservoir and a solution gas reservoir, in terms of bubble point -- the importance of the bubble point?

MR. HIGUERA: Can I just have Tom Zadick address that?

MR. GILL: Yes, please.

If you'll come to the microphone, if you wouldn't mind.

First of all, make sure we're on the same page. If I could impose on you to define, or at least explain how you understand a retrograde condensate reservoir.

MR. ZADICK: Well, basically there are two types of hydrocarbon reservoirs.

MR. GILL: Can you speak up just a touch?

MR. ZADICK: Basically, there are two types of hydrocarbon reservoirs. There are reservoirs that are all oil, we refer to those as oil reservoirs. That means they're a liquid at reservoir pressure and temperature.

And then there are reservoirs that are gas. So those are the two outliers. And by gas, we're talking about something that's compressible, it's very fluid, it's similar to the air that we breathe.

Now, there are also reservoirs that we refer to -- hydrocarbon reservoirs that we refer to as two-phase reservoirs. And that's a reservoir that has an oil column and a gas cap.

Now, retrograde reservoirs are reservoirs that are all gas, initially, at reservoir condition. And as you produce the reservoir and the pressure falls in that reservoir, instead of going through a bubble point and making gas evolve from the liquid system, you go through a dew point. And liquid condenses. Similar to think about precipitation. When it rains, we get to a point where the atmosphere can no longer hold all the water that's entrained in the atmosphere. And if the temperature drops a little bit, things liquefy, and then it starts to drop out.

One of the concerns that people have about retrograde reservoirs is that if you go below the dew point and you start to drop out liquids, you will reduce the amount of liquids that you ultimately recover. So in those cases it's very important to try to do something to maintain reservoir pressure.

Now, in our case here at Providence, we don't have a retrograde reservoir. What we have is a highly volatile, undersaturated oil. So it's all liquid at reservoir conditions. But as Ed was trying to explain, because it's very volatile there's an extreme amount of shrinkage that occurs. So it's important that you do try to maintain reservoir pressure.

Reservoir pressure can be maintained in more than one way. One is, it can be maintained by an aquifer. Our model does have a constant pressure aquifer built in below the oil water contact. But because the reservoir is so low in permeability, the aquifer isn't very efficient at maintaining reservoir pressure.

So the second thing that we tried to look at was to inject gas to help maintain reservoir pressure. Now there was some good news and some bad news about that. The good news was that it appeared that the process worked fairly well, but the bad news was we only have two wells. And because we converted one of the wells to gas injection, it really didn't end up helping our overall recovery.

MR. GILL: For gas injection, you certainly have to have some sort of communication between the wells. And at the distance you're -- what is the distance between those two wells? Is it a mile and a half?

MR. ZADICK: It's like about a quarter section away.

MR. GILL: Say again?

MR. ZADICK: About a quarter of a section away. So they're very close.

MR. GILL: Okay, then. And then my understanding is -- is if you go past the dew point or the bubble point, let's say when it's still at that point you are about 40 percent recovery, rule of thumb.

MR. ZADICK: That rule of thumb doesn't apply very well to this reservoir because, as I tried to explain with the PVT data, the bubble point of the reservoir is very close to the initial reservoir pressure. The initial reservoir pressure is around 3600 pounds, and the bubble point is around 3450, roughly, as I recall. So the minute you incur about 100 pounds in pressure drop in either the producing pressure or the average reservoir pressure, then gas is going to evolve from the liquid phase and form a secondary hydrocarbon phase.

MR. GILL: So you are really -- okay, that's an important point, that the -- let's just say from a textbook perspective. If you can keep it in the phase that it's in as long as possible, you can get more recovery over time, and the magnitude could be maybe ten -- you know, 100 percent, 200 percent more than if you can if you fall on the other side of that phase. It may not --

MR. ZADICK: I'm not sure I agree with you on the magnitude numbers. But I do agree that, all things being perfect -- if this was an ideal world and we could produce this reservoir without reducing the reservoir pressure, we would recover more oil than we do by allowing the reservoir pressure to decline.

MR. GILL: But because the initial reservoir pressure and the bubble point, theoretically, are so close, any production -- okay. That was something I needed to clarify. That was -- okay. Thank you.

CHAIRMAN JOHNSON: Does the Board have other questions?

Mr. MacDonald, do you have any redirect for Mr. Higuera?

MR. MACDONALD: Yes, Mr. Chairman. If I could have a moment, though, to consult, yes.

CHAIRMAN JOHNSON: Mr. MacDonald, would you like to take a five-minute break?

MR. MACDONALD: That would be great, Mr. Chairman. Thank you.

(A break was taken from 4:09 p.m. to 5:14 p.m.)

CHAIRMAN JOHNSON: Okay, Mr. McDonald, I think we're back to you.

MR. MACDONALD: Okay, Mr. Chairman. Based on discussions with the Division and the Bureau of Land Management, Wolverine is willing to make the following motion with respect to this Request.

Under the Board's authority, under Utah Administrative Code Rule R649-3-6.3, which reads that the Board may take any other action the Board deems appropriate in the circumstances, the parties have stipulated as follows:

Wolverine would be authorized to conduct additional testing on the two wells in question, including recompletion efforts as outlined in their testimony; and after six months of production from each well, to report back to the Board to provide additional updated information and testimony to meet the requirements for further flaring and venting authorization. The limitation would be that it would be no more than 2 million cubic feet of gas -- is that correct -- per day. They cannot exceed that amount during this testing period.

MR. GILL: Question: Is that motion that the recompletion or the reworking is in the Navajo zones?

MR. MACDONALD: Yes. Yes. It would be in the two productive zones. Navajo 1 is actually the -- you would recomplete the Navajo 1, right? Yes.

MR. ALDER: And the Division concurs in that motion and feels that would be the best way to get the additional information and make the determinations that are required by the rules.

MR. MACDONALD: Mr. Chairman, would you also like a member from the BLM just to confirm that?

CHAIRMAN JOHNSON: I know that you've consulted with the BLM on that issue.

MR. CHRISTENSEN: And I concur --

CHAIRMAN JOHNSON: Would you please identify yourself for the record?

MR. MACDONALD: Just identify yourself for the record.

MR. CHRISTENSEN: You bet.

Mr. Chairman and Board Members, my name is Cornell Christensen. I'm the field office manager for the Bureau of Land Management in the Richfield area, which oversees this issue that we have before the Board. And we concur with the Division and also with Wolverine for this motion.

CHAIRMAN JOHNSON: Thank you.

MR. JENSEN: Clarification: The one concern I have -- and I don't think it's intended, but when we say six months from both wells, what I wouldn't want to see is that Wolverine ends up producing out of the Navajo 1 and don't produce -- and so now they go 15 or 18 or 24 months and haven't produced out of the other. So they haven't ever got to the six months of production from both wells.

(A discussion was held off the record.)

MR. MACDONALD: All right.

MR. HAROUNY: Mr. MacDonald, wouldn't that be clarified and resolved if we just put 120 million cubic feet total volume on it, which is basically 2 million a day, regardless of which formation it's producing from?

MR. MACDONALD: We can do it that way, too.

MR. HAROUNY: It's simple enough.

CHAIRMAN JOHNSON: Sorry.

MR. MACDONALD: Mr. Chairman, the problem is, is again, the 24-1 well is currently producing in the Navajo 2, and we wouldn't want to prematurely abandon production from that zone, as well. So Mr. Harouny offered a compromise on it to put a limitation -- again, Mr. Harouny?

MR. HAROUNY: Limitation would be 2 million cubic feet gas a day -- flared gas a day for a period of six months, which would bring the total -- limit it to a total volume of 120 million cubic feet of gas, regardless of which formation, which will --

MR. JENSEN: It's more than that, isn't it? It's got to be more than that. Six months?

MR. HAROUNY: Sorry, six months per day, whatever that -- 180 times two. Just limit it to 2 million a day.

MR. JENSEN: So 360 million.

CHAIRMAN JOHNSON: So that would be a maximum of 180 times 2 million. 360 million flared or vented --

(The reporter interrupted for clarification.)

CHAIRMAN JOHNSON: 360 million cubic feet over the six-month period.

MR. ALDER: I think the Division thought it would just be six months from either well, six months production, flaring production. Does that say the same thing?

MR. HAROUNY: Same thing.

MR. HUNT: No more than six months.

MR. HAROUNY: No more than six months. The volume is limited to that total volume of flared gas.

MR. MACDONALD: That's the aggregate to be flared from both wells?

MR. HAROUNY: Correct.

MR. MACDONALD: Okay.

MR. GILL: Six months, but in any event not to exceed --

MR. JENSEN: 360.

MR. ALDER: We think it's more certain if it's not more than six months' production -- flared. I should let Mr. Hunt...

MR. HUNT: No more than six months' production from each well. So you're worried that the way they worded it, one well could go on producing for a --

MR. JENSEN: -- never get to two months.

MR. HUNT: -- if you limit it to six months for each well.

MR. GILL: But if it gets to that volume limit in five months, they have to stop.

MR. HAROUNY: Yes. The volume is very important.

MR. GILL: Is that your understanding?

MR. MACDONALD: I understand what you are trying to set is some limitation for the total gas to be flared.

MR. HAROUNY: Correct.

MR. ALDER: That's an additional --

MR. HAROUNY: Yeah.

MR. ALDER: That's fine.

MR. JENSEN: Six months or 360 million, whichever comes first.

MR. HAROUNY: Correct.

CHAIRMAN JOHNSON: Mr. Alder, did you have any other comments on that, on the motion by Mr. MacDonald?

MR. ALDER: No. We think it's appropriate and recommend that the Board adopt it.

CHAIRMAN JOHNSON: What's the pleasure of the Board?

Mr. Payne?

MR. PAYNE: I move that we grant the motion requested and as modified by Mr. Harouny with the volume limitation.

CHAIRMAN JOHNSON: Is there a second?

MR. JENSEN: Second.

CHAIRMAN JOHNSON: Any discussion?

All those in favor of granting the motion?

THE BOARD: Aye.

CHAIRMAN JOHNSON: It's unanimous.

We'll grant the motion as you stated, Mr. MacDonald. Would you prepare the Order?

MR. MACDONALD: I will, Mr. Chairman.

CHAIRMAN JOHNSON: And then submit it to the Board's counsel?

MR. MACDONALD: Yes.

CHAIRMAN JOHNSON: Thank you. And to the Division.

MR. MACDONALD: And to the Bureau of Land management. We'll provide it to all parties.

CHAIRMAN JOHNSON: Okay. I might be a little late here.

Is there anyone else would who would like to address the Board on this matter, since we've only made a six month decision? Seeing none.

MR. GILL: Mr. Chairman, I move we adjourn.

CHAIRMAN JOHNSON: Well, I appreciate everyone's indulgence with us today. This has not gone like normal matters do.

I hope Wolverine understands the Board is very interested in you being successful in your ventures. Glad we can work this out.

And I, personally, being a resident of Sanpete County, hope you are very successful in your ventures.

We are not going to adjourn yet. Your motion -- you may leave, thank you.

But we have a third docketed matter here that's going to be continued. So I just need to read it into the record.

(The third docketed item was heard from 5:25 p.m. to 5:26 p.m.)

CHAIRMAN JOHNSON: We're back on the record.

MR. MACDONALD: Mr. Chairman, a housecleaning matter on the Wolverine docket. We'd like to move for admission of Exhibits A through V inclusive, including Supplemental Exhibit E --

CHAIRMAN JOHNSON: P?

MR. MACDONALD: Well, no, that's Substitute Exhibit P and Supplemental Exhibit E.

MR. ALDER: And the Division has no objection to the admission of any of those exhibits.

CHAIRMAN JOHNSON: Does the Board have any objections?

MR. JENSEN: Well, I just question the relevancy of the exhibits, given the order that we've just granted and whether that ought to be --

MR. MACDONALD: Well, part of that, Mr. Jensen would be -- is the decision and the stipulation and agreement is based on that exhibits. They would have to be supplemented based on the Board's order, anyway, depending on what the production results would be.

MR. ALDER: I think it's better to have them in the record, and -- in case we come back and visit this again, some of the evidence will be in the record.

Anyway, we have no objection to their being admitted at this time.

CHAIRMAN JOHNSON: Are there any particular exhibits you are concerned about?

MR. JENSEN: I think there are a number of exhibits there that, given the order that's there, that absolutely have no relevance and maybe cut the other way. I'm just suggesting that maybe you ought to think about holding all of your exhibits, and -- you are going to come back, anyway.

MR. MACDONALD: Well, my only concern was that part of the decision-making was based on some of the exhibits that were submitted. And I would suggest that it's better to have them in the record and then either substituted or superceded by exhibits as we come forward in front of the Board six months after the production results -- or after the production.

MR. ALDER: My concern is that the testimony is -- to the extent that that ever is revisited, is -- really needs the exhibits, and under normal circumstances would have been admitted as we'd gone along.

MR. MACDONALD: Right.

MR. ALDER: I'd ask that you accept them.

CHAIRMAN JOHNSON: Mr. Jensen, are you okay with the exhibits?

MR. JENSEN: Well, it's the applicant who's got to live with it.

MR. MACDONALD: I understand. But we would have the opportunity again, Mr. Jensen. Based on my understanding of the order, is that some of that data would be superceded or rendered irrelevant by additional exhibits that would be done. But my concern is the decision that was made today, and the motion and order, has to be based on the exhibits that were presented and testimony presented as part of the decision-making that the Board determined that other action was appropriate.

MR. JENSEN: I'll defer to you.

CHAIRMAN JOHNSON: Okay. Then, the exhibits are entered.

MR. MACDONALD: All right. Thank you.

CHAIRMAN JOHNSON: Thank you. We're adjourned.

(The matter was adjourned at 5:29 p.m.)